Reducing Energy Cost with Distributed Energy Systems

A case study investigating the profitability of various distributed energy systems for a food manufacturing factory in southern Norway.

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Preface

This thesis is our final project as part of the two-year master's program Industrial Economics and Technology Management at the University of Agder. The thesis investigated the profitability potential of various distributed energy system configurations for a factory in southern Norway. We identified this as an interesting topic when the European energy prices were very high earlier in our study. The thesis has been a very good way of combining a technical focus with financial and management accounting concepts and methods. With very little knowledge of distributed energy systems before we began our research, it has been very interesting to dive into such a timely and relevant topic and to combine this with the subjects included in our master's program.

We would like to express our gratitude to Hennig-Olsen Is for allowing us to use them as our case research object, for their willingness to share their practices and experiences, and for excellent cooperation during these months. We would also like to thank our supervisor, Dr. Rafael Heinzelmann, for most excellent supervision, guidance, and feedback throughout our project.

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Abstract

The European energy market has in 2022 and 2023 been characterized by significantly higher and more volatile prices. Future prices are expected to be lower than this, but still higher and more volatile than the historical average of the previous decade through at least the 2030s. The industrial sector therefore faces added energy costs as well as uncertainty. In addition, the cost of solar photovoltaic panels (PV) and battery energy storage systems (BESS) have decreased a lot in the last decade. Therefore, looking at whether the use of PV and BESS in a distributed energy system (DES) can help reduce energy costs for factories in the industrial sector is timely and relevant.

To research this, a case study of 'Hennig-Olsen Is' (HOI) located in Hannevika, Kristiansand has been caried out. After an initial literature review, primary data was collected at the factory of HOI through semi-structured interviews, several informal meetings, and a detailed factory tour. The scope was then prioritized before conducting the analysis using a specialized software for DES analysis named HOMER Grid. Future energy price prognoses from Statnett and The Norwegian Water Resources and Energy Directorate was used to simulate energy prices through the project lifetime.

The analysis results indicate that investing in DES in 2024 is likely not profitable as future energy prices are not expected to be high enough to justify the investment costs. However, the analysis of the 2030s scenarios implies waiting to invest could make the configurations of DES be more profitable. Overall, leasing of solar PVs was assessed to be the preferred option as it provided a better present worth and was considered less risky. The analysis show that BESS can reduce demand charge through peak shaving, while PV reduces energy charge by replacing grid electricity in real time in our case. However, these charge reductions are quite heavily influenced by case-specific factors such as energy consumption patterns, and energy grid tariff. A sensitivity analysis was performed to determine the necessary component cost reductions needed to make various DES configurations profitable. The results showed that a significant cost reduction is needed, particularly regarding BESS.

Keywords: Distributed energy system, profitability analysis, energy cost reduction.

Sammendrag

Det europeiske energimarkedet har i 2022 og 2023 vært preget av betydelig høyere, og til tider mer volatile priser. De fremtidige prisene forventes å være lavere enn dette, men fortsatt høyere og mer volatile enn det historiske gjennomsnittet for det foregående tiåret gjennom i hvert fall 2030-tallet. Industrisektoren møter da økte energikostnader og usikkerhet. Samtidig har kostnadene for solcellepaneler (PV) og batterienergi-lagringssystemer (BESS) sunket mye det siste tiåret. Derfor er det relevant og rettidig å se på om bruk av PV og BESS i et distribuert energisystem (DES) kan bidra til å redusere energikostnadene for fabrikker i industrisektoren.

For å undersøke dette gjennomførte vi et casestudie av 'Hennig-Olsen Is' (HOI) lokalisert i Hannevika i Kristiansand. Etter et innledende litteraturstudie ble primærdata samlet inn ved fabrikken til HOI gjennom semistrukturerte intervjuer, uformelle møter, og en omfattende fabrikkomvisning. Deretter ble omfanget avgrenset før analysen ble utført. Analysen ble gjort i en spesialisert programvare for DES-analyse kalt HOMER Grid. Fremtidige energipris-prognoser fra Statnett og Norges vassdrags- og energidirektorat ble brukt til å simulere energipriser gjennom prosjektets levetid.

Resultatene av analysen indikerer at investering i DES i 2024 trolig ikke er lønnsomt da de fremtidige energiprisene ikke forventes å være høye nok til å rettferdiggjøre investerings-kostnadene. Samtidig indikerer analysen av 2030-scenarioene at det kan være lønnsomt å vente med å investere til 2030. Leasing av solcellepaneler ble vurdert som det foretrukne alternativet da det ga en bedre nåverdi og ble ansett som mindre risikabelt enn kjøp. Analysen viser at BESS kan redusere effektleddet gjennom "peak shaving", mens PV reduserer energileddet ved å erstatte elektrisitet fra nettet i sanntid. Imidlertid er disse kostnadsreduksjonene ganske sterkt påvirket av case-spesifikke faktorer som energiforbruksmønstre og strømavtaler. En sensitivitetsanalyse ble utført for å fastslå de nødvendige kostnadsreduksjonene for å gjøre ulike DES-konfigurasjoner lønnsomme. Resultatene viste at det er behov for betydelige kostnadsreduksjoner, særlig angående BESS.

Nøkkelord: Distribuert energisystem, lønnsomhetsanalyse, reduksjon av energikostnader

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Abbreviations

Abbreviation	Explanation
AC	Alternating Current
BESS	Battery Energy Storage System
CAPEX	Capital Expenditures
CDF	Cumulative Distribution Function
DC	Direct Current
DCF	Discounted Cash Flow
DES	Distributed Energy System
HOI	Hennig-Olsen Is
IRR	Internal Rate of Return
k	Kilo (thousand)
LCOE	Levelized Cost Of Energy
M	Mega (million)
NPC	Net Present Cost
NPV	Net Present Value
O&M	Operation & Maintenance
PV	Photovoltaic
RRR	Required Rate of Return
W	Watt
Wh	Watt hour
Wp	Watt peak (nominal power)

1 Introduction

The European energy market, especially the electricity market, has in 2022 and 2023 been characterized by significantly higher, and at times more unpredictable prices (Statistics Norway, n.d.; The Electricity Price Committee, 2023, p. 17). Now while this was mainly caused by the Russian gas company Gazprom exporting far less gas to the European market than what was expected (The Electricity Price Committee, 2023, p. 18), it emphasized the challenges that can follow as a result of higher energy prices. While prices are not expected to remain as high and volatile as in 2022, they are expected to remain higher and more volatile than the historical average of the previous decade through the 2030s at least (Statnett, 2023b, pp. 47, 62). For the industry we can argue that this constitutes added costs as well as uncertainty. At the same time the cost of investing in solar photovoltaic panels (PV) or battery energy storage systems (BESS) have dropped significantly in the recent decade (DNV, 2021, p. 13; IRENA, 2022, pp. 90–91; Kichou et al., 2022, p. 2). When solutions such as solar PVs or BESS are located close to energy consumers they are referred to as distributed energy systems (DES) (Alanne & Saari, 2006). DES is explained in more detail in chapter 3.3. The energy and industry sectors are in the challenging process of changing to greener emission-free ways of operating which will require more renewable energy sources than we have today (NOU 2023: 3, pp. 9, 23, 44).

With the expectation of higher and more volatile energy prices, cheaper DES solutions, and the need for more renewable energy sources, it is timely and relevant to investigate how renewable DES solutions can be used to address the issue of more expensive energy from an industrial point-of-view. In this thesis we therefore ask our main research question:

- RQ1: How can a production facility use Distributed Energy Systems based on renewable energy sources to reduce overall energy costs?

We expand on this main research question by adding three supporting research questions.

- RQ1-1: What is the profitability of the different possible DES configurations?
- RQ1-2: How is an overall cost reduction achieved by the DES solution?

- RQ1-3: If a DES configuration is not profitable, what must change for it to become profitable?

We have researched this by looking at the factory of Hennig-Olsen Is (HOI), situated in Hannevika in Kristiansand, Norway. We investigate the profitability potential of installing PVs and/or BESS and compare these to the existing factory layout as a base case. Various other DES solutions have been considered but have been dismissed for various reasons which is described in chapter 5.4.

2 Case

In this thesis our research has been centered around the ice cream producer Hennig-Olsen Is and their factory in Hannevika in Kristiansand, Norway. HOI is the oldest ice cream producer in Norway and was founded in 1924 (Hennig-Olsen Is, n.d.). They produce about 32 million liters of ice cream and frozen desserts annually at the factory in Hannevika. This constitutes almost half of the Norwegian market. They also produce their own chocolate, caramel, croak, and jam.

HOI is an interesting case company for several reasons. Their production lines, as well as storage facilities, are rather energy-intensive with the need for both very cold and pretty warm temperatures in numerous steps of the lines. They have already installed solar PVs on some of the factory roofs and therefore have actual first-hand experience with the performance of solar PVs at their location. They have also recently upgraded their energy monitoring system, so they are able to provide accurate and high-fidelity data on energy consumption throughout the factory. The factory can also be sub-divided into parts that have different energy characteristics. The solar PVs deliver their power to the storage facilities. Storage facilities have more static energy consumption, while the production facilities are more dynamic. The factory production schedule is mainly influenced by two factors. First is the seasonal variation in market demand, where more ice cream is sold in the summer than during winter. The second is labor cost, where production staff is working day and evenings, but very rarely at night as the labor costs becomes unnecessary high. Both factors coincide with when the potential for solar PV electricity generation is highest.

3 Theory

In this chapter we present the analysis software we have used to perform our profitability calculations. We then present the investment analysis concepts that we use to assess our analysis results before we present relevant theoretical DES concepts.

3.1 HOMER Grid

HOMER stands for "Hybrid Optimization of Multiple Energy Resources". HOMER Software offers three different hybrid power system software called HOMER Pro, HOMER Grid, and HOMER Front. HOMER Software has been used as a tool in several researches and projects by over 250 000 users in over 190 countries (HOMER Software, n.d.).

In this thesis we have used HOMER Grid which is an optimization tool that helps assess distributed energy systems, behind-the-meter, and grid-connected technologies, to examine what solution can lower electricity costs through demand charge reduction and energy arbitrage. As there is a large number of technology options, complex tariff structures, variation in costs, and availability of energy resources, deciding on which solution to go for can be difficult. The software allows the user to design a model to represent the project being examined. HOMER Grid simulates all operations of the system for each time step of the year, where it compares energy demand and supply to calculate all energy flows in the system, including whether energy storages should be filled, used, or ignored (HOMER Grid, n.d.-c). In our simulation a time step of 60 minutes was chosen as this matched the highest available resolution in our input data. This operation is done repeatedly for all possible configurations, in other words all combinations of DES components and other variables that are added. By repeating the same simulation over and over again, with small variations to the optimizing algorithm, accuracy in the results are increased the results start to converge. In our simulation each configuration was simulated 200 times as this was found to be a sufficient compromise between the need for accuracy and processing constraints. HOMER Grid then assesses the feasibility of each configuration before calculating the lifetime cost of each configuration. These configurations are compared to a base case, which in our simulations is the factory as it stands today without adding any DES solutions at all. This comparison answers whether a configuration is considered profitable or not, and how it competes against other alternatives.

HOMER Grid can also optimize the sizing of the DES components to optimize in terms of cost (HOMER Grid, n.d.-k). This algorithm is called “HOMER Optimizer®”. We have not used this algorithm as it is incompatible with multi-year inputs such as long-term electricity price prognosis that we have used. We therefore sized our components manually.

3.2 Investment analysis

In this chapter, different investment analysis concepts and techniques used to investigate and assess the different simulated investments scenarios are presented and explained. These concepts are typically used within management accounting and corporate finance for assessing investment opportunities. In addition, more energy adapted investment analysis concepts are presented. Therefore, combining these concepts and techniques are considered to be suitable to help with the assessment of the profitability analysis of different DES configurations.

3.2.1 Net present value and net present cost

The net present value (NPV) is a discounted cash flow method where it calculates the difference between the present cash inflow and the present value of future cash outflow over a given period. The NPV method considers the time value of money (Bhimani et al., 2019, p. 391). The principle behind the time value of money is that money today is worth more than money in the future (Bhimani et al., 2019, p. 391; Bredesen, 2019, p. 62). Therefore, the cash flows in different time periods have different values and must be discounted to present day to be comparable. The NPV uses a required rate of return (RRR), often called the discount rate, to represent the minimum required rate of return on an investment in addition to the time value of money by discounting the cash flow to present time. Consequently, determining a representative discount rate and cash flow is important as slightly adjustment can change the NPV. Discount rates are explained in chapter 3.2.4. A positive NPV typically indicates that the project is worth undertaking, while a negative NPV indicates the project is not. (Bhimani et al., 2019, p. 391; Hussain et al., 2005, p. 1).

The NPV can be calculated through Formula 1 (Bredesen, 2019, pp. 113–114).

$$NPV = -CF_0 + \sum_{t=1}^{n} \frac{CF_t}{(1+i)^t} \tag{1}$$

where:

NPV	Net present value
CF_0	The investment cost when the investment object is acquired
CF_t	Cash flow in period t
i	Required rate of return or discount rate
n	Number of time periods or project lifetime

HOMER Grid calculates the net present cost (NPC) instead of the NPV. The Department of Finance in Northern Ireland describes the NPC like this when calculating the NPV: "*Where the sum of discounted costs exceeds that of the discounted benefits, the net figure may be referred to as the Net Present Cost (NPC). Alternatively, the term 'negative NPV' may be used*" (DoF, 2015). If there are enough revenues on the project to exceed the costs, HOMER Grid will show the NPC as a negative value. According to HOMER Grid (n.d.-e) the NPV and the NPC differ only in sign, and a lower NPC indicates a better investment opportunity. HOMER Grid uses the discount factor when calculating the NPC, and thereby have factored out inflation (HOMER Grid, n.d.-e).

3.2.2 Risk-free rate

The risk-free rate represents the highest return one can theoretical get in the future with the lowest risk. Typically, a proxy used for the risk-free rate is long-term treasury bonds (Bredesen, 2019, p. 111; Hussain et al., 2005, p. 1; Van Binsbergen et al., 2022, p. 1). For this thesis a 10-year Norwegian treasury bond from the central bank of Norway is used. At the date of 25.03.2024 a 10-year Norwegian treasury bond have a generic interest rate of 3,566% (Norges Bank, n.d.-a).

3.2.3 Inflation

Inflation can be defined as *"the decline in the general purchasing power of the monetary unit"* (Bhimani et al., 2019, p. 404). Inflation has to be considered since "*[…] declines in the general purchasing power of the monetary unit […] will inflate future cash flows above what they would have been had there been no inflation"* (Bhimani et al., 2019, p. 404).

The central bank of Norway has a target for inflation close to 2%, where the consumer price index (CPI) is used as a measure of inflation. Since the CPI is affected by price volatility, such as energy prices, the underlaying trend in prices can be noisy. Therefore, the central bank of Norway use the CPI adjusted for tax changes and excluding energy products (CPI-ATE) for the underlying inflation (Norges Bank, n.d.-b). In this thesis an average of the CPI-ATE from January 2006 to October 2023 is used. The average is calculated to be 2,2% through the csv-file available at the site to the central bank of Norway (Norges Bank, n.d.-c).

3.2.4 Discount rate

The discount rate, also known as the RRR, is used to calculate the present value of a future nominal cash flow and reflects the opportunity cost of investing (Bhimani et al., 2019, p. 391; Hussain et al., 2005, p. 1). Typically used in the NPV method, the discount rate can be a tool to assess which project one should invest in by comparing the project to other alternatives with similar risk profiles and considering the returns one can get (Bhimani et al., 2019, p. 391). Studies have shown that firms tend to use only a single discount rate to value all of their projects (Bierman, 1993, Graham & Harvey, 2001, as cited in Krüger et al., 2015, p. 1253). Since the discount rate is representing risk associated with the project, choosing a discount rate that is not representing this project-specific risk can lead to overestimating riskier projects, while underestimating safer projects (Krüger et al., 2015, p. 1253). In addition, for project with cash flows occurring well into the future, the discount rate have a strong impact on the results (Short et al., 1995, p. 8).

Discount rates can also be considered based on the industry (Short et al., 1995, p. 4). Fujita (2023, pp. 9–10) have with the weighted average cost of capital (WACC) estimated an average discount rate of 7,29% for the industrial sector. Oxera (2011, p. 21) have through surveys and calculations estimated a discount rate of 6%-9% for investments in solar PV. For project lacking investment-specific data, a discount rate of 10% is recommended (Short et al., 1995, pp. 8–9).

Determining the discount rate is not a simple task as it is usually based on factors such as the cost of capital, interest rates, inflation, rate of return, risk premium, planning horizon, taxes and more. Some of the ways to set the discount rate is: opportunity cost of capital, the cost of capital, WACC, risk-free rates, companies' hurdle rate, market rates, and more (Short et al., 1995, pp. 6–8). Many assumptions of the future must be made, and therefore the discount rate can vary a lot. A risk-adjusted discount rate can reflect uncertainty, variability and risk associated with the project (Short et al., 1995, pp. 27–28). In simple terms, this risk-adjusted cost of capital can be calculated as shown in Formula 2 (Bredesen, 2019, p. 112).

$$Cost\ of\ capital = (Risk\ free\ rate) + (Risk\ premium) \qquad 2$$

Since discount rates is often associated with the companies' risk tolerance, and financing solution through equity and/or debt, a discount rate has not been calculated for this thesis. Therefore, various discount rates have been used instead. These discount rates are shown in Table 1.

Table 1: The discount rates used in this thesis.

Discount rates	3,566%	6%	8%	10%	12%

When simulating, HOMER Grid uses the annual real discount rate, which is the discount rate adjusted for inflation. Formula 3 shows how the real discount rate is calculated in HOMER Grid (HOMER Grid, n.d.-f).

$$i = \frac{i' - f}{1 + f} \qquad 3$$

where:

i	Real discount rate
i'	Nominal discount rate (the rate at which you could borrow money)[1]
f	Expected inflation rate

HOMER Gird uses the real discount rate when calculating the discount factor used in the NPC calculation as shown in Formula 4 (HOMER Grid, n.d.-b).

$$f_d = \frac{1}{(1+i)^N} \qquad 4$$

f_d	Discount factor
i	Real discount rate in %
N	Number of years

3.2.5 Internal rate of return

The internal rate of return (IRR) calculates the discount rate which makes the NPV equal to zero (Bhimani et al., 2019, p. 393). *"It gives the return in % on the capital that is tied up in a project at any given time"* (Bredesen, 2019, p. 128). Typically, the IRR is used to be compared with the cost of capital or hurdle rate. If the IRR is higher than the cost of capital, the project is accepted, and if the IRR is less than the cost of capital, the project is rejected (Bredesen, 2019, pp. 130–131; Short et al., 1995, p. 54).

Although a high IRR may look more desirable than a low IRR, the IRR does not count for the size of the investment, lifetime, or different cash flows. For instance, comparing the IRR with a project A and B, can lead to B having the highest IRR, but the lowest NPV. This makes comparing IRRs less useful when the considered investments can be very different (Bredesen, 2019, pp. 131–132; Short et al., 1995, pp. 53–54).

[1] For this thesis, different rates are used, and not a rate of borrowing money as shown in Table 1.

The IRR can be calculated by solving for IRR either through trying and failing, financial calculator or Excel when the NPV=0 as shown in Formula 5 (Bredesen, 2019, pp. 128–129).

$$0 = NPV = -CF_0 + \sum_{t=1}^{n} \frac{CF_t}{(1+IRR)^t} \tag{5}$$

where:

NPV	Net present value
CF_0	The investment cost when the investment object is acquired
CF_t	Cash flow in period t
IRR	Internal rate of return
n	Number of time periods or project lifetime

HOMER Grid "*calculates the IRR by determining the discount rate that makes the present value of the difference of the two cash flow sequences equal to zero*"(HOMER Grid, n.d.-a).

3.2.6 Levelized cost of energy

The levelized cost of energy (LCOE) is also known as the levelized cost of electricity (Bruck et al., 2018, p. 133; Short et al., 1995, pp. 47–50). The LCOE takes all the costs of the DES project and compares it with all the energy the system is producing through its entire lifetime (Kost et al., 2018, p. 29). The LCOE method is well-known as a useful way to compare different energy technologies in terms of their cost, scale and operation of time (Allan et al., 2011, p.23, Joskow 2011, Lai and McCulloch 2016, p.2, Liu et al 2015, p.1531, Orioli and Di Gangi 2015, p.1992, as cited in Kost et al., 2018, p. 30; Short et al., 1995, p. 47). The ability to compare different DES project with not typically comparable components is what that makes the LCOE-metric unique.

All though the LCOE is useful when assessing different systems, the method cannot be used alone for a profitability analysis (Kost et al., 2018, p. 31; Ueckerdt et al., 2013, p. 1). The author points out that *"the LCOE is a cost-based figure and does not include revenues"* (Kost et al., 2018, p. 31).

Formula 6 shows HOMER Grid's calculation of the LCOE, (HOMER Grid, n.d.-d).

$$LCOE = \frac{C_{ann,tot} - C_{boiler}H_{served}}{E_{served}} \qquad 6$$

where:

LCOE	Levelized Cost of Energy in NOK/kWh
$C_{ann,tot}$	Total annualized cost of the system in NOK/kWh
C_{boiler}	Boiler marginal cost in NOK/kWh[2]
H_{served}	Total thermal load served in kWh/year[3]
E_{served}	Total electrical load served in kWh/year

$C_{ann,tot}$ are calculated as shown in Formula 7 (HOMER Grid, n.d.-i).

$$C_{ann,tot} = CRF\left(i, R_{proj}\right) \cdot C_{NPC,tot} \qquad 7$$

where:

$C_{NPC,tot}$	The total net present cost in NOK
i	The annual real discount rate in %
R_{proj}	The project lifetime in year
CRF()	A function returning the capital recovery factor

[2] Since this thesis is not looking at thermal energy, $C_{boiler} = 0$.

[3] Since this thesis is not looking at thermal energy, $H_{served} = 0$.

While the E_{served} is calculated as shown in Formula 8 (HOMER Grid, n.d.-j).

$$E_{served} = E_{served,ACprim} + E_{served}, DCprim + E_{served,def} + E_{grid,sales} \quad (8)$$

where:

E_{served}	Total electrical load served in kWh/year
$E_{served,primAC}$	AC primary load served in kWh/year
$E_{served,primDC}$	DC primary load served in kWh/year
$E_{served,def}$	Deferrable load served in kWh/year
$E_{grid,sales}$	Energy sold to the grid in kWh/year

3.2.7 Leasing

An alternative to purchasing is leasing. Merrill (2020) defines a lease as *"a transfer of an asset for a limited time in return for periodic payments called rent" (Merrill, 2020, p. 1)*. Merrill (2020, pp. 4, 11) argues that leasing is a flexible method of holding assets, where the asset being leased have to be tangible and the lease time have to be less than the expected useful life of the asset. Leasing can be an alternative when upfront capital is limited. Risk associated with maintenance can be shifted to the lessor (Bredesen, 2019, p. 255; Lin et al., 2013 as cited in Merrill, 2020, p. 15). Typically, lease agreement can be divided into operational leasing, which have a short lease time, and financial leasing, which usually have a long lease time. Operational leasing agreements are easier to terminate (Bredesen, 2019, p. 255). An option can be agreed to buy the asset for its residual value after the lease term (Merrill, 2020, p. 28).

Leasing will not typically generate tax advantages as opposed to owning an asset (Merrill, 2020, p. 13). According to Elcon in Bredesen (2019, p. 255), can leasing give a tax advantages through greater tax deduction in comparison to loans since the collected depreciations in loans are lower than the total rent in the leasing period. Taxes and residual value complicate the profitability calculation of leasing versus buying. If taxes and residual value is ignored, the calculation can be done by comparing the NPV of the lease and the NPV of the buying case (Bredesen, 2019, p. 256).

3.2.8 The payback method

The payback method calculates how many periods it takes before the investment cost is paid back by the accumulated cash flow. The payback method does not account for the size or return of the project, in addition it does not account for the cash flow that occurs after the payback period. On the other hand, since it shows how far into the project the turning point occurs, the payback method can tell us something about how risky the project is. The further into the future the payback happens, the more uncertain can the project be as market conditions can change (Bredesen, 2019, pp. 171–176). *"What the maximum payback period should be must necessarily be a discretionary consideration"* (Bredesen, 2019, p. 175). Typically, the company sets a limit for the maximum payback period they can accept. Are there no limit, the payback method favors the shortest payback period (Bredesen, 2019, pp. 171–173).

The payback method can be calculated as the simple payback, which does not account for the time value of money, or the discounted payback which does account for the time value of money. The payback period is calculated by comparing the investment cost with the sum of the positive cash flow which equals the investment cost (Bredesen, 2019, pp. 171–174; Short et al., 1995, pp. 56–58). "*Distributed power systems are typically not as simple, and the income must be defined relative to some alternative"* (HOMER Grid, n.d.-a). HOMER Grid calculates both the simple and discounted payback by comparing the project with the base case (HOMER Grid, n.d.-a).

3.2.9 Sensitivity analysis

Although the future is associated with uncertainty, projects with a long lifetime cannot omit the consideration of risk (Bredesen, 2019, p. 191). If the timing and size of a given amount is known with certainty, there should not be any risk. But that is most often not possible to know. By understanding how sensitive certain variables is in the project can give a sense of how risky the project is. This can be done by execute a "Wat if"-analysis known as a sensitivity analysis. Such an analysis illustrates the risk by looking at how the profitability changes if different assumptions is changed. This is done by changing variables like discount rate and prices in both a favorable and unfavorable direction, which should show the crossing point for when the project is profitable and not. If the changes and crossing point in profitability is graphed in terms of the NPV and the sensitivity variables, a more steeper graph indicates that the project is more sensitive to its corresponding variable in contrast to slacker graphs (Bredesen, 2019, pp. 192–197; HOMER Grid, n.d.-l). HOMER Grid does a sensitivity analysis when multiple values are specified for single value variables (HOMER Grid, n.d.-h).

3.2.10 Present worth

The present worth tells how much money is saved over the system's lifetime by investing in the project in comparison with the base case. HOMER Grid calculates the present worth by taking the difference between the NPC of the base case and the considered project (HOMER Grid, n.d.-a).

3.2.11 Return on investment

The return on investment (ROI), also known as the accounting rate of return, is an economic metric that tells the ratio between income and cost of an investment. Typically, one will accept investment with a more positive ROI than the required rate of return. It is a popular measure as it takes revenues, costs, and investment into account in a single number. However, one should not use this metric solely alone (Bhimani et al., 2019, p. 588; Bredesen, 2019, pp. 176–177).

HOMER Grid defines ROI as "*yearly cost savings relative to the initial investment*" (HOMER Grid, n.d.-g). HOMER Grid calculates the ROI by taking the "*the average yearly difference in nominal cash flows over the project lifetime divided by the difference in capital cost*" through Formula 9 (HOMER Grid, n.d.-g). In other words, HOMER Grid calculates the annualized ROI.

$$ROI = \frac{\sum_{i=0}^{R_{proj}} C_{i,ref} - C_i}{R_{proj}(C_{cap} - C_{cap,ref})} \tag{9}$$

where:

$C_{i,ref}$	nominal annual cash flow for base (reference) system
C_i	nominal annual cash flow for current system
R_{proj}	project lifetime in years

C_{cap} capital cost of the current system

$C_{cap,ref}$ capital cost of the base (reference) system

3.3 Distributed Energy Systems

Distributed energy systems are systems of energy generation and storage located close to energy consumers (Alanne & Saari, 2006). They can be stand-alone off-grid systems, or they can be connected to the centralized grid. Distributed Energy Systems may add flexibility in the decision-making process by adding optional energy sources that for instance can be utilized when the centralized power cost is very high (Krishan & Suhag, 2019). Such sources can be on-site generation like photovoltaic solar cells or diesel generators, or on-site energy storage systems that can either be charged from a centralized source or by on-site generation (Alanne & Saari, 2006). This can reduce uncertainty by adding flexibility that decision-makers can exercise greater control over (Gawusu et al., 2022; Krishan & Suhag, 2019).

3.3.1 Photovoltaic cells

Solar energy as a renewable, emission-free alternative to fossil fuels has received much attention as the global energy demand continues to increase while humanity is addressing the issues of global warming (Zhou et al., 2023). Photovoltaic cells convert solar energy into electrical energy by using semiconductor materials to exploit the photovoltaic effect (Pavlík & Mamchur, 2023). The most common form of PV cells are made of silicon (Zhou et al., 2023). The photovoltaic effect is where photons hit the cell and excite electrons causing them to jump from the valance band to the conduction band (Pavlík & Mamchur, 2023). This generates direct current (DC) which then is run through an inverter to produce alternating current (AC) that can be used on-site, be delivered to the grid, or stored in a battery for later use (Zhou et al., 2023). There are different forms of silicon PV cells with the most common being monocrystalline and polycrystalline (Pavlík & Mamchur, 2023). Monocrystalline PV cells have a higher power generation yield per area than polycrystalline PV cells and are also more cost efficient (Jiang et al., 2020).

3.3.2 Battery energy storage systems

Renewable energy sources such as wind and solar power need to be harvested when they are available, as opposed to fossil fuels which can be used to generate energy at customer demand (Koohi-Fayegh & Rosen, 2020). If demand is not sufficient when the sun is up, or winds are blowing the energy needs to be stored for later consumption to avoid waste. BESS offer fast response times, geographical independence and the ability to sustain power delivery over longer periods and is therefore widely accepted as a potential solution to the challenges brought by uncontrollable renewable energy sources (Yang et al., 2018). Various types of batteries exist but in this thesis we focus on lithium-ion (Li-ion) batteries as these have a very high efficiency, long lifetime and high storage capacity (Koohi-Fayegh & Rosen, 2020). They are also the dominant battery technology for stationary storage systems (DNV, 2022).

3.3.3 Peak shaving, valley filling, and time shifting

Peak shaving is the management of overall energy demand to reduce short-term demand spikes and is the most efficient technique to reduce power bills for clients who pays demand rates (Gawusu et al., 2022). Distributed generation such as combustion engines and generators are considered the best way to peak shave, but with the maturing of BESS technology solar PV combined with BESS is now becoming the best solution for peak shaving as the BESS adds additional flexibility to further optimize timing (Gawusu et al., 2022, pp. 13, 20). The requirement is that the DES solution can respond quickly and be regulated by the operator. Valley filling is in many ways the opposite of peak shaving where leftover demand capacity is utilized by increasing the load by for instance charging the BESS (Krishan & Suhag, 2019). Time shifting (also referred to as arbitrage) means buying electricity when energy rates are low to store it and use it later when energy rates are higher (Krishan & Suhag, 2019). Energy storage systems can enable time shifting for energy consumers.

4 Methodology

In this chapter we explain the basis for our case study, our research design, and how we went about collecting empirical data.

4.1 Case study

This research was conducted as an embedded single-case study with the purpose of conducting a techno-economic assessment of the profitability potential of DES at HOI. A single-case format was chosen to allow us to delve as deep as possible into the details and complexity of this particular case in order to construct the most convincing narrative to support our conclusions and, as Messner et al. (2017) argues is necessary, gain a thorough understanding of the empirical setting. A lot of effort was put into gaining a robust understanding of the inner workings of the factory and to properly understand these as Stake (1995) also argues that one must study *“the particularity and complexity of a single case”* (Stake, 1995, p. xi) to comprehend the activities under a central context. Yin (2018, p. 61) argues that significant improvements can happen within the analytical segment of the study by having two or more cases, as single-case designs can be vulnerable alone. On the other hand, rationales for single-case designs such as; critical, unusual, common, revelatory, or longitudinal case cannot be satisfied by multiple-cases (Yin, 2018, pp. 49–54). Although it could be interesting to compare several production plants, a multiple-case will make it hard to answer the research question since the optimization of DES for a production plant depends on so many individual factors that can influence the optimization solution. Silverman (2010, p. 104) states that within qualitative research, the researcher is prepared to sacrifice scope for detail. The scope for this thesis is limited to a single case study to ensure that a proper understanding is gained of the case object and its context within our given timeframe in order to enable convincing conclusions. While the case study approach, especially the single-case format, limits the possibility of statistical generalizations it enables analytic generalizations (Yin, 2018, p. 21), by allowing the case *“to shed empirical light on some theoretical concepts or principles”* (Yin, 2018, p. 38). The case-study is therefore well suited to answer research questions of “how” and “why”, as in our thesis (Yin, 2018, p. 4).

Yin (2018) distinguishes between single-case and multiple-case in four types as both a single-case and multiple-case study can be holistic and embedded. Yin (2018) illustrates this as shown in Figure 1. In our research we have studied various transformers (electrical consumers) within the factory of HOI under various electricity market conditions. The different transformers represent different embedded units within the same case as they have unique consumption patterns and levels, while the factory with its location, electricity tariffs, and so on represents the case and context levels. Our case study therefore fits the Type 2 case study as described by Yin (2018).

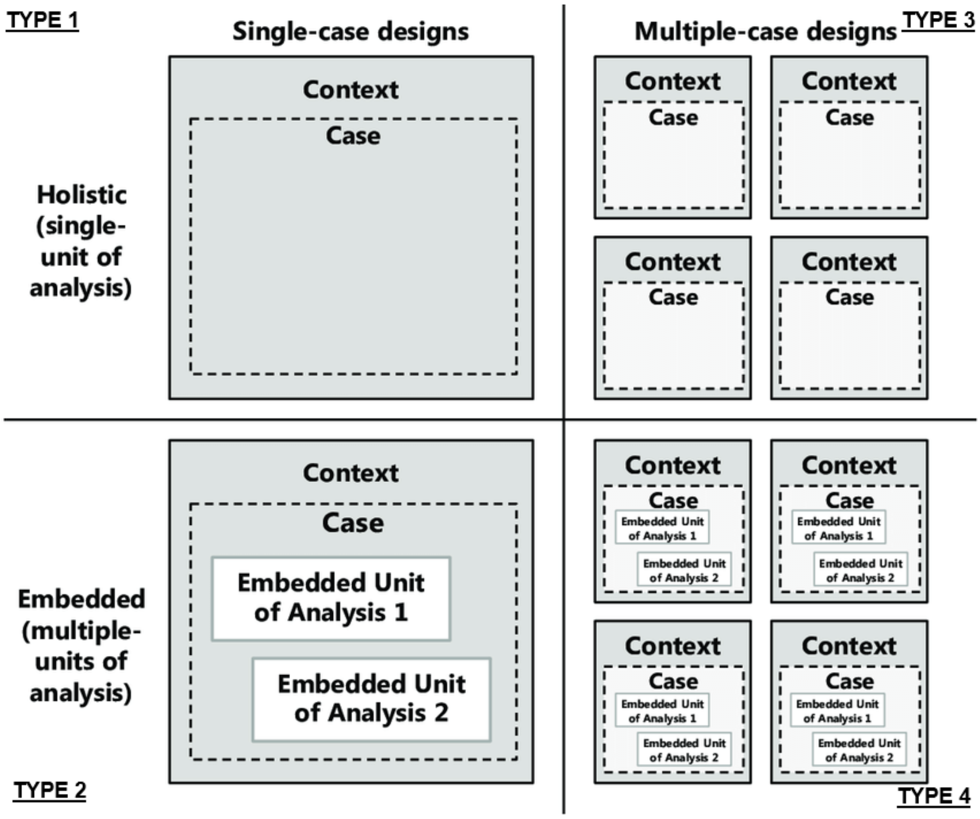


Figure 1: Basic types of designs for case studies (Yin, 2018, p. 48).

A case-study can be conducted with a hard approach where the method should be general and replicable to other researchers, or it can be conducted with a soft approach where the importance of context and uniqueness of a case is emphasized (Stake, 1995; Yin, 2018). Validity, reliability, and generalizability are typically quality criteria for a hard approach to case studies, while authenticity, plausibility and criticality are the quality criteria for evaluating how convincing a soft approach qualitative study is (Golden-Biddle & Locke, 1993; Messner et al., 2017). Ahrens and Chapman (2006, p. 837) argues that the concepts of validity and reliability are unsuited for qualitative case-based research *"due to a failure to appreciate the significant distinction between method and methodology".* As our study on HOI takes place in today's world with today's knowledge and factors, it is not certain that the findings and conclusion would be the same if the same case study was carried out at a different time even if the method was the same. Therefore, a soft approach is most suitable for this research. Authenticity must be provided through our first-hand experience within the field, while plausibility is secured through the empirical connection to existing works and theory (Golden-Biddle & Locke, 1993). Criticality refers to how the text challenges existing ideas and beliefs (Golden-Biddle & Locke, 1993), perhaps such as whether or not solar PVs are a profitable investment. According to Golden-Biddle and Locke (1993) it is not an absolute pre-requisite for good field-based research, such as authenticity and plausibility are.

The case study should "*derive its excitement and justification through little more than the description of a particular phenomenon"* (Siggelkow, 2007, p. 20). For this thesis, it can be argued that the ice cream producer 'Hennig-Olsen Is' is a well-suited case object for several reasons.

4.2 Research design

Our case-study follows what Yin (2018, pp. 229–230) describes as a linear-analytic approach which is a typical approach for most articles in experimental science and is advantageous for a thesis such as this one. After gaining an initial overview of the research problem and our case subject, we conducted a literature review to gain an understanding of the specifics of DES-related research, technical aspects, and relevant investment analysis concepts. The research structure is mainly exploratory as it seeks to answer how changing the current situation will affect the case business, but it also has explanatory and descriptive elements to it as it is necessary to describe and explain the status quo to understand the potential effects of the alternatives.

The research question is derived of some broad and initial theory. Before the collection of primary theory, Yin (2018) suggests to do some preliminary fieldwork first. Ahrens and

Chapman (2006) notes that *"doing qualitative field studies is not simply empirical but a profoundly theoretical activity"* (p. 820). Ahrens and Chapman (2006) elaborate that reflection of data against theories is an continues process within qualitative field studies. We had our first meeting with HOI in November 2023 where we discussed the research question with them and gained some initial knowledge into how their factory operated. After the initial literature review in January and February 2024 we developed a data collection plan and conducted the field work at HOI in the beginning of March 2024. We have also had numerous email exchanges and phone calls before and after the data collection.

Dubois and Gadde (2002) discusses a concept of "*systematic combining*". When conducting a case study, one might detect unexpected empirical findings that is of relevance and interesting to look deeper into. Further, the authors explains that this can cause the need to take another direction of the theoretical framework. This concept is illustrated in Figure 2. An abductive research design is used for this case study as both the theoretical and empirical understanding changes and develops throughout the study. This generates the need to revisit and iterate on both theoretical and empirical ideas and preconceptions. As Dubois and Gadde (2002) argues around the importance of the fit between theory and data. The "…*data should not be forced to fit preconceived or preexistent categories, asserting rather that the categories are to be developed from data*" (Glaser (1978, p. 4) cited by Dubois & Gadde, 2002, p. 556). Dubois and Gadde (2002) believe an abductive approach can yield more in contrast to inductive approach.

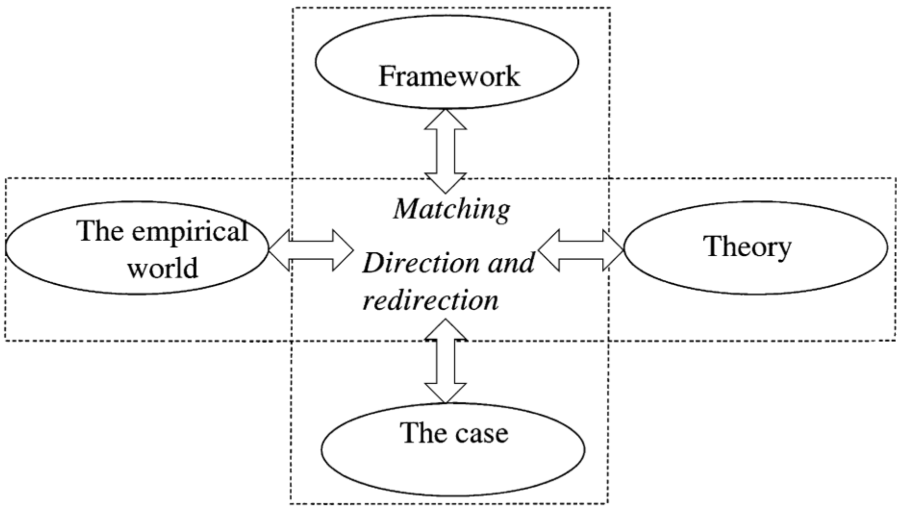


Figure 2: Systematic combining (Dubois & Gadde, 2002, p. 555).

This research is based on a mixed research strategy of quantitative and qualitative data sources. The quantitative data sources are both primary sources such as energy consumption data from the factory of HOI, as well as secondary data such as electricity price information and predictions.

This strategy of triangulation can help improve the credibility of the research process (Messner et al., 2017). In our case study a lot of the data is quantitative data that has been logged by sensors around the factory, but it is then interpreted together with the statements by the informants which gives multiple inputs especially to "how" and "why" questions, as these require a qualitative explanation rather than just numbers. This helps us validate data such as energy consumption history when evaluating whether or not it is a suitable baseline for future years as well. Having electricity price prognosis from both NVE and Statnett is another way of triangulating.

4.3 Collection of empirical data

To gain an understanding of HOI's production factory and their situation in relation to the energy marked, semi-structured interviews with four employees were conducted over a two-day period in the beginning of March 2024. The audio of the interviews was recorded, transcribed, and then coded. The employees interviewed represented senior management (informant 1), technical maintenance (informants 2 and 3), and procurement (informant 4). Stake (1995) argues that case studies are suited *"to obtain the descriptions and interpretations of others"* (Stake, 1995, p. 64). Formal interviews are one way of achieving this and to ensure consistency all informants should be asked the same questions in the same order and phrasing (Doody and Noonan (2013) cited in Hoque et al., 2017, p. 322). The employees where asked the same questions from the same interview guide, but some questions were omitted from certain interviews as they were assessed to be outside the informant's field of expertise, and we chose to prioritize the limited time with each interview subject on questions we assessed to most likely provide us with relevant and reliable data. The omitted questions dealt mainly with detailed technical descriptions of the factory facilities. In the same period as the interviews, an extensive tour of the factory was conducted to observe equipment, personnel, and processes in action. A couple of informal meetings with factory staff have also been held.

The first in November 2023, and the last two during the days of the interviews. In addition to this we have had a close dialogue with HOI via email and phone to plan interviews, handle information requests, and answer follow-up questions.

The main data variables and sources collected were characteristics related to the factory and its energy usage, technical characteristics of potential energy solutions, data and predictions for the energy market and the current grid tariffs, as well as environmental data such as the number of solar hours and wind speeds. In addition to this, the interviews provided valuable context and additional information to these variables. The most relevant data sources and variables are summarized in Table 2.

Table 2: The most relevant empirical data.

Main data category	**Data sub-category**	**Data variable**	**Data sources**	**Collection method**
Factory characteristics	Energy usage	Power distribution to various transformers/loads, and power consumption patterns	HOI Energy Surveillance system, HOI personnel	Pre-compiled reports from HOI, access to the energy surveillance system, interviews, factory tour
	Energy costs	Grid tariffs, power purchase agreements	HOI, Nord Pool (for spot prices)	Interviews, emails Exported via Forbrukerrådet (n.d.) web page
	Building restrictions and possibilities	Available area for DES solutions, height restrictions,	HOI,	Interviews, factory tour

		noise restrictions, ground conditions,		
		District heating availability	Å Energi (to confirm District Heating was still available)	Web search
DES Characteristics	Solar PV	Performance	HOI, HOMER Grid	Interviews, access to the solar PV monitoring system of HOI, HOMER Grid PV database, data sheets
		Cost	HOI	Interviews and email
			DNV (2021), IRENA (2022), Hjelme et al. (2023),	Web search
	Li-ion BESS	Performance	HOMER Grid	HOMER Grid database
		Cost	Berg et al. (2021), Kessels et al. (2017), DNV (2023), Murray (2023)	Web search
Energy Market	Future price prognosis	Short- and long-term prognosis for average energy	Statnett (2023a, 2023b)	Web search

		prices and price variations in NO2 (2023-2050) Long-term prognosis for average energy prices in NO2 (2023-2040) Government reports on the energy market	 The Norwegian Energy Regulatory Authority (2023) NOU 2023: 3, The Electricity Price Committee (2023)	 Web search Web search
Environmental data	Solar radiation		HOMER Grid The Norwegian Meteorological Institute HOI	Built in solar radiation model Web search Solar PV monitoring system

In the upcoming sub-chapters, we will describe how these data variables have been operationalized in our analysis.

5 Analysis

The first tree sub-chapters of this chapter explain and evaluate the various input variables that had to be determined to conduct the HOMER analysis. This includes the factory energy consumption, available area for new solar PVs, DES costs, electricity tariffs, and prognoses for future electricity prices. After this a sub-chapter explaining how we came to prioritize solar PVs and BESS as the DES configurations to investigate is presented. Finally, the various simulation results are presented. Detailed tables of all the simulation results are available in Appendix A.

Each simulation scenario and subsequent configuration has a unique code that is described in Table 4. An overview of all simulation scenarios are given in Table 5. When sensitivities are applied to DES component pricing, this mean that a multiplier between 0 and 1 is applied to discover at what price a configuration becomes profitable. E.g. if the sensitivity is found to be 0.6 this indicates that a cost reduction of 40% of that specific component cost is needed to make the configuration at least break even. Sensitivities were varied in steps of 0.05 as smaller steps than this was found to be too time consuming and computer processing demanding. The highest sensitivity that returned a profitable configuration is presented for each configuration. This is the sensitivity that is closest to the breakeven value.

The cost and size of the solar PV and BESS are the same in every 2024 scenario, and in every 2030 scenario. The dimensions of solar PV system are not varied, as there is no more area for solar PVs on the roof and a lower effect does not make the project more profitable. Therefore, a nominal power of 375kWp is used for every scenario (except in scenario 11 (N-H-24-1) where additional simulations were run to investigate the effects of varying the BESS and PV capacity sizes). For BESS the capacity has a minimal effect on profitability as there are no economies of scale effect in the price data available for such BESS sizes. Therefore, a size of 100kWh is used on every scenario (except scenario 11 where additional sizes are also simulated). If anything, a smaller battery can be more affordable as the average price during peak shaving or time shifting can be higher at max battery utilization. Table 3 shows the input for prices and effect for solar PVs and BESS.

Table 3: Cost and effect input for each scenario.

	Solar PV	BESS
Size	375kWp	100kWh
Capital cost	8943 NOK/kW[4]	3242,51 NOK/kWh
Replacement cost[5]	-	1621,225 NOK/kWh
O&M cost	44,67 NOK/kW pr. year[4]	86,5 NOK/kWh pr. year
Capital cost 2030	5400 NOK/kW	2190 NOK/kWh
Replacement cost 2030[5]	-	1535 NOK/kWh
O&M cost 2030	27 NOK/kW pr. year	58,47 NOK/kWh pr. year
PV Leasing cost (O&M)[6]	745 NOK/year	

Table 4: Analysis scenario coding scheme.

Source	Prognosis	Year	Sensitivity	Discount rate (Nominal)	Configuration[7]
S = Statnett N = NVE	L = Low B = Basis H = High	24 = 2024 30 = 2030	1 = All sensitivities set to 1 S = Sensitivity DES component cost analysis	3 = 3,566% 6 = 6% 8 = 8% 10 = 10% 12 = 12%	A = Base Case B = BESS (Capital cost sensitivity) C = PV Buy D = PV Buy + BESS E = PV Leasing F = BESS (Capital cost & Replacement cost sensitivity)

[4] Not used when PVs are leased.

[5] The technical life span of solar PVs are equal to or longer than the project life time of 25 years used in these simulations. PV Replacement costs are therefore not relevant. BESS replacement happens after 15 years.

[6] There are no "leasing input" in HOMER Grid, so to simulate leasing, the cost of leasing PV is inserted as O&M cost in HOMER Grid and capital cost set to zero.

[7] In configuration B, sensitivity values are only applied to BESS capital cost, while in configuration F sensitivity values are applied to both BESS capital cost and BESS replacement cost at the same time.

Table 5: Analysis scenario overview.

Scenario	Scenario code	Prognosis	Sensitivity	Project start
Scenario 1	S-L-24-1	Statnett LOW	N/A	2024
Scenario 2	S-L-24-S	Statnett LOW	Sensitivity	2024
Scenario 3	S-B-24-1	Statnett BASIS	N/A	2024
Scenario 4	S-B-24-S	Statnett BASIS	Sensitivity	2024
Scenario 5	S-H-24-1	Statnett HIGH	N/A	2024
Scenario 6	S-H-24-S	Statnett HIGH	Sensitivity	2024
Scenario 7	N-L-24-1	NVE LOW	N/A	2024
Scenario 8	N-L-24-S	NVE LOW	Sensitivity	2024
Scenario 9	N-B-24-1	NVE BASIS	N/A	2024
Scenario 10	N-B-24-S	NVE BASIS	Sensitivity	2024
Scenario 11	N-H-24-1	NVE HIGH	N/A	2024
Scenario 12	N-H-24-S	NVE HIGH	Sensitivity	2024
Scenario 13	S-L-30-1	Statnett LOW	N/A	2030
Scenario 14	S-B-30-1	Statnett BASIS	N/A	2030
Scenario 15	S-H-30-1	Statnett HIGH	N/A	2030
Scenario 16	N-L-30-1	NVE LOW	N/A	2030
Scenario 17	N-B-30-1	NVE BASIS	N/A	2030
Scenario 18	N-H-30-1	NVE HIGH	N/A	2030

5.1 Energy characteristics of the factory

The electricity consumption of HOI is divided over several main electrical switchboards and transformers. The majority of HOI's energy usage is through production and storage. The considered loads are presented in Table 6.

Table 6: Considered loads for the simulations.

Transformer	What it powers	Total consumption 2023
H10	Engine room storage	3,536 MWh
H11	Engine room production	1,943 MWh
H12	Engine room production	2,608 MWh
H5	Production	3,673 MWh

The existing solar PVs is connected to transformer H10 which supplies the cooling storage compressors with electricity. These PVs have an installed nominal power of 615 kWp and can be seen in Picture 1 in chapter 5.2. All electricity generated by the solar PVs is consumed by H10 consecutively. Informants 2 and 3 informed us that their conclusion after the first months of operating the PVs were that it was more profitable to use all the electricity generated themselves instead of selling excess power on the grid. The energy consumption characteristics for H10 can be seen in Figure 3 and Figure 4 for 2022 and 2023 respectively.

According to informants 2 and 3, batteries were not interesting to look at for H10 because the solar power generation tends to coincide with when the electricity cost is high. HOI can also adjust the cooling effect for shorter periods of time to reduce energy consumption when the spot price is high, or load demand is high. This makes the potential for peak shaving or load shifting poor.

Similar adjustments cannot be made to the cooling compressors in the production facilities as the production is very sensitive to temperature variations. Therefore, informants 2 and 3 thought it would be interesting to see if a BESS solution could be used to supply the production lines in the periods were the spot price is high. The cooling compressors for the production lines are supplied through transformers H11 and H12 and the yearly energy consumption pattern for 2023 can be seen in Figure 5. The actual production lines are supplied through transformer H5 and can be seen in Figure 6. Informants 1, 2, and 3 pointed out that critical equipment on the production lines already get their electricity distributed through an uninterruptible power supply (UPS), which is a small battery bank that is designed to deliver emergency power to allow for graceful shutdown of sensitive equipment, and to spare sensitive equipment from noise on the electrical grid. The UPS is however not dimensioned to supply the production with power for prolonged periods of time like a BESS is.

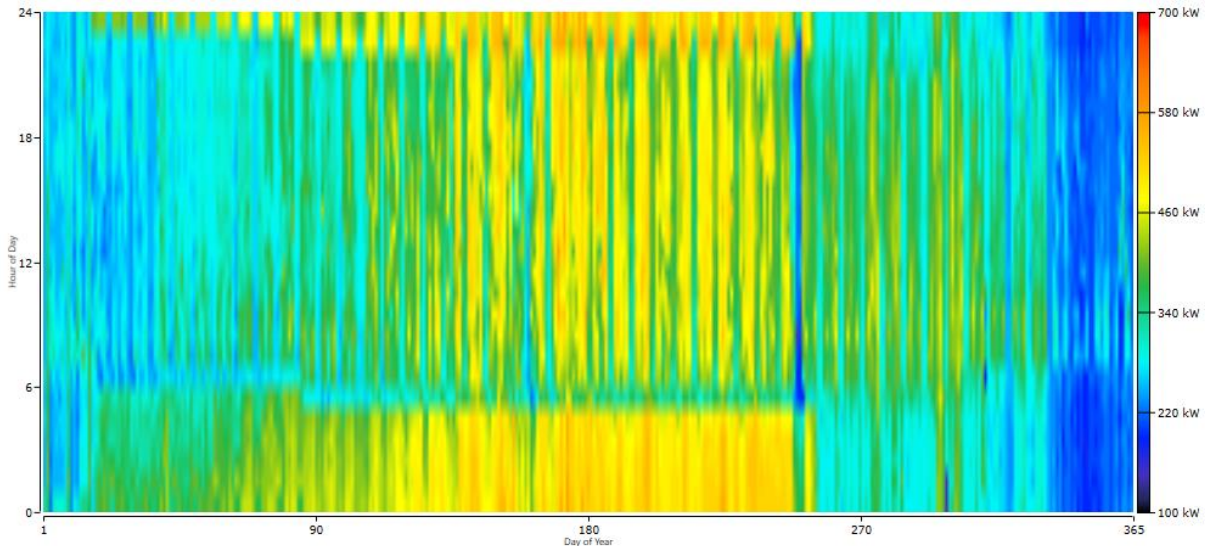


Figure 3: Energy consumption for the cooling storage through transformer H10 in 2022, before the solar PVs where installed.

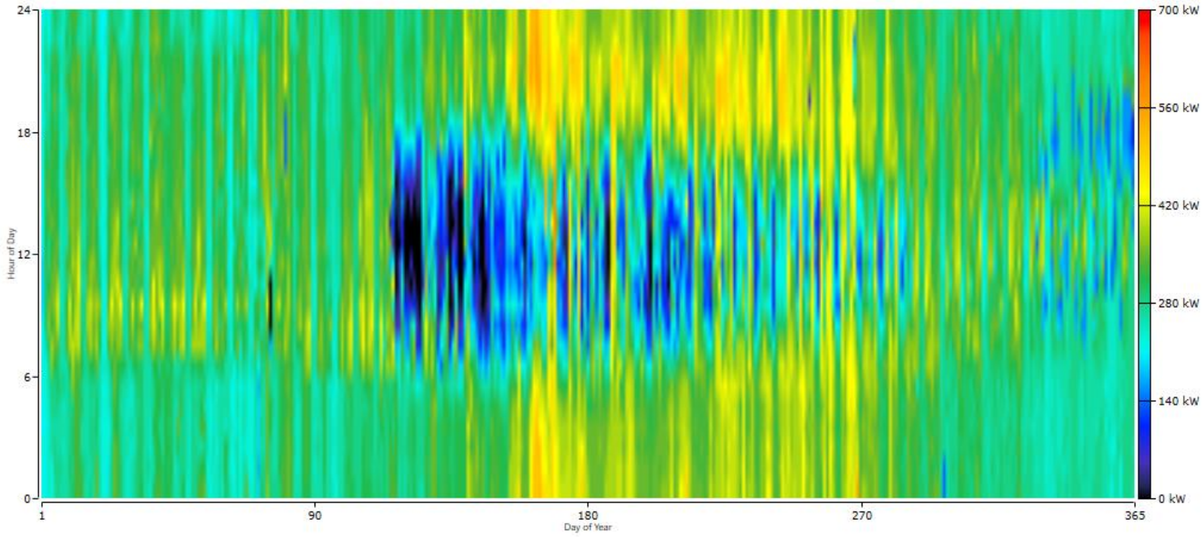


Figure 4: Energy consumption for the cooling storage through transformer H10 in 2023. The solar PVs came online on day 117 (27th April 2023).

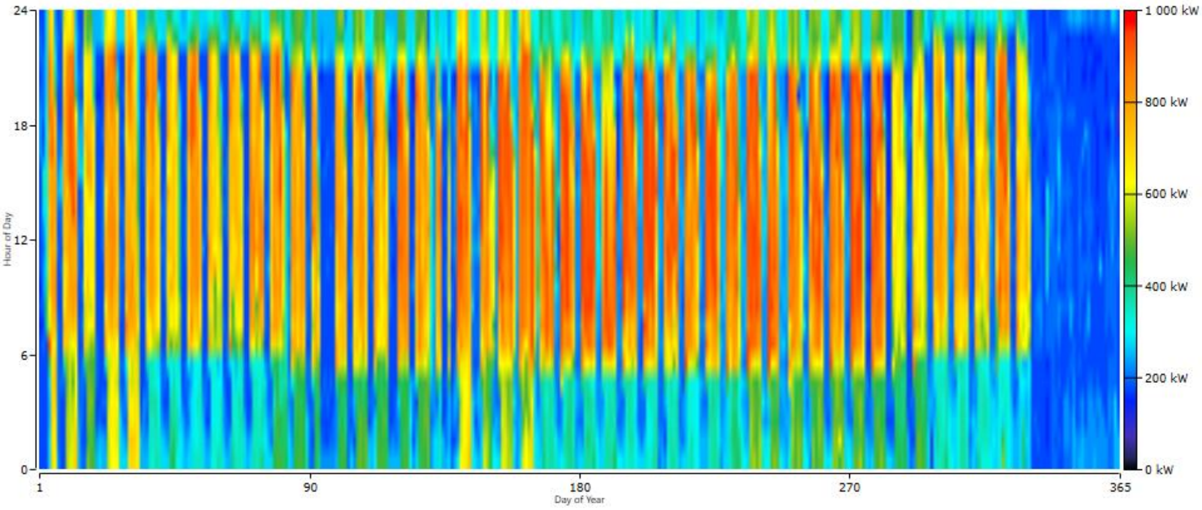


Figure 5: The hourly energy consumption of the production facilities cooling compressors, transformers H11 and H12. The figure shows how energy consumption is mainly concentrated in daytime from 0600 to 2000 (when not on daylight savings time) on weekdays. Production is halted in December. Energy consumption is highest in the summer months when the outside ambient temperature is highest.

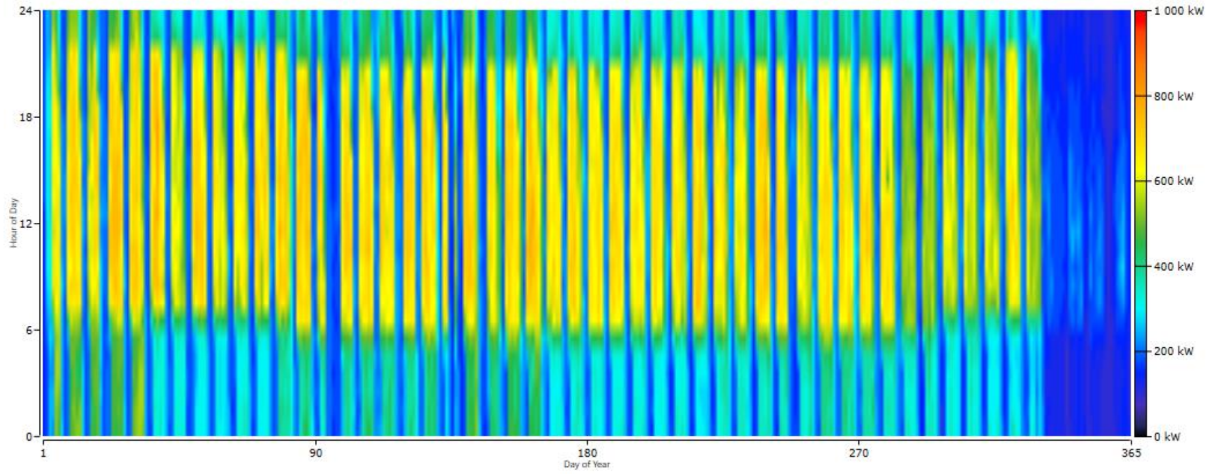
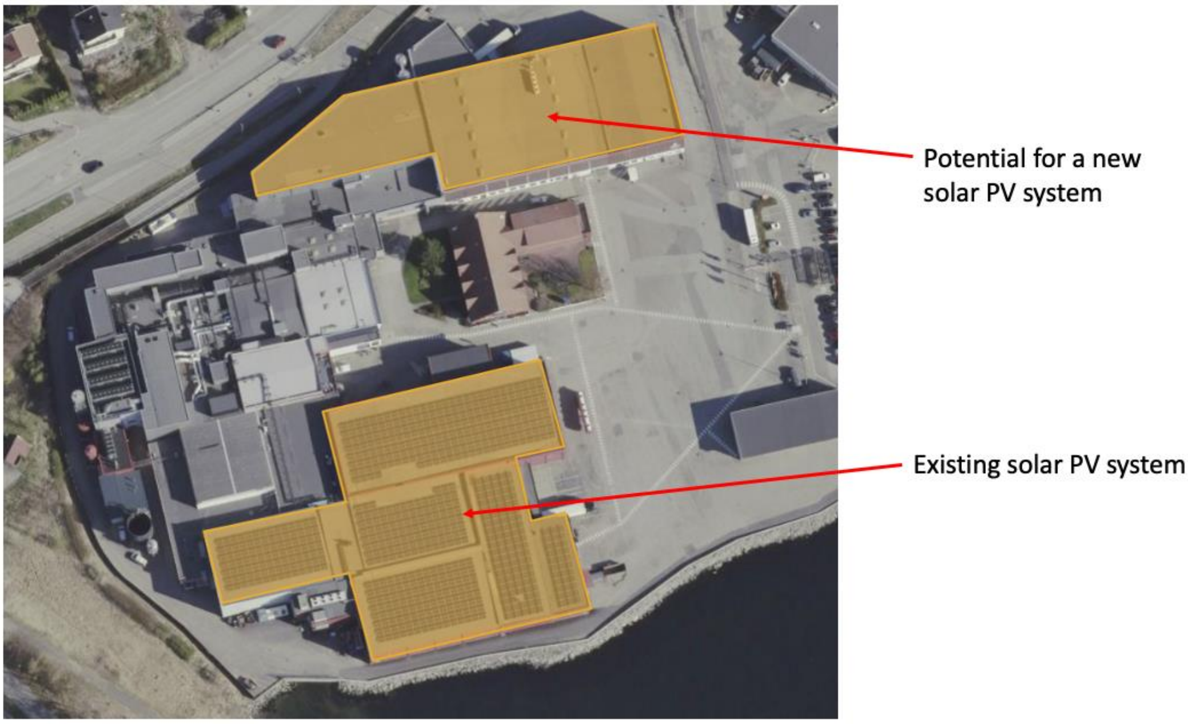


Figure 6: The energy consumption of transformer H5 which supplies the production lines themselves. The consumption pattern coincides with that of H11 and H12.

These three transformers (H5, H11 and H12) have similar load patterns with a much more dynamic consumption pattern than transformer H10. This could indicate a greater potential for peak shaving, valley filling, and time shifting. As these three transformers are so similar we chose to only simulate the sum of H11 and H12 as a single transformer while not simulating H5 at all. With such similar consumption patterns, any findings regarding one transformer are highly likely transferable to the two other transformers. This freed up processing power that we instead could use to run more scenarios and sensitivity values.

5.2 Solar PV area

Informants 2 and 3 have shared information about the existing solar PV system. The system consists of 1108 LONGI Solar LR4-72HPH-460M modules and 238 LONGI Solar LR4 72HBD-445M modules. These are monocrystalline silicon PV cells. These modules are connected to four Sungrow SG110CX inverters. Data sheets for PVs and inverters are enclosed in Appendix B. Installed nominal power on this system is 615kWp. HOI uses all the produced electricity themselves through only one transformer. If they consider expanding their existing solar PV system with a new solar PV system, they will run that energy through a different transformer. As there are limited space on HOI’s facility, the informants designate the highlighted roof top shown in Picture 1 for where an expansion should take place. There is some room for an expansion between these two roof tops as well, however there is a lot of variations, shadows, and other installations on theses roofs which can make an installation of PV modules difficult and complicated. Hence, this thesis only looks at the potential highlighted roof top.



Picture 1: Aerial photo of the factory of HOI, potential roof top for a new solar PV system, and the existing solar PV system (Norgeskart, n.d.).

Through Norgeskart (n.d.) “draw and measure” tool, the roof top for the potential expansion is estimated to be 3237 m^2, while the roof with existing PV panels have an area of 5310 m^2. Based on the existing solar PV system and estimated roof area, a nominal power for the potential new PV system is calculated to be 375 kWp as shown in Table 7.

Table 7 also shows the specific energy of the PV panels. The specific energy is the ratio between peak power and the annual energy generated and is a measure for how efficient the solar panels are compared to the theoretical peak power. HOMER Grid estimates about 8% higher efficiency for the new panels in our simulation, than what was registered in real life during the first year of operating the existing panels. One year of data is hard to draw any conclusions from. When we compare the registered number of sunny hour at the weather station at Kjevik 10 km away, we see that in the first 12 months of operation the registered number of sunny hours was 1659,5 while the yearly average since January 2000 has been 1998,8 (The Norwegian Meteorological Institute, n.d.-a). The last 12 months has in other words been almost 17% less sunny than an average year. Even though the number of solar hours is not synonymous with total solar radiation, as the latter depends on the time of day, it is reasonable to conclude that HOMER Grid is not overestimating the specific energy of the potential new solar PVs.

Table 7: Estimated roof area and solar PV effect for existing and new solar PV system.

Roof Hennig-Olsen Is	Roof area (m^2)	Total (kWp)	Annual energy generated (MWh)	Specific Energy (kWh/kWp)
Roof with existing PV panels	5310	615	497,705 (Measured in first year of operation)	809,28
Roof for potential new PV panels	3237	375	327,875 (HOMER Grid estimate)	874,33

There was also a discussion with informant 3 to investigate the potential use of the parking lot just outside of HOI's facility as shown in Picture 2 (Norgeskart, n.d.). The idea here was to build a roof with solar PVs for the parking lot. However, it was concluded that there is no point to investigate this further when the profitability basis on the fabric roof is so poor. It would be more expensive from a construction point of view to expand with a solar PV system, in addition to a new roof at the parking lot.

Picture 2: HOI parking lot (Norgeskart, n.d.).

5.3 Prices

Our analysis relies on several price estimates that are presented in this sub-chapter. First prices for investing in and operating solar PVs and BESS are presented. After this the electricity grid tariffs of HOI are presented before we present and explain how we have estimated future electricity spot prices.

5.3.1 PV prices

There has been a significant drop in prices of solar PV. From 2009 to 2022 prices of crystalline silicon module have dropped on average 91% (DNV, 2021, p. 13; IRENA, 2022, pp. 90–91). Figure 7 shows the price decline of solar PV from 2010 to 2050 in Europe by technology and manufacturing.

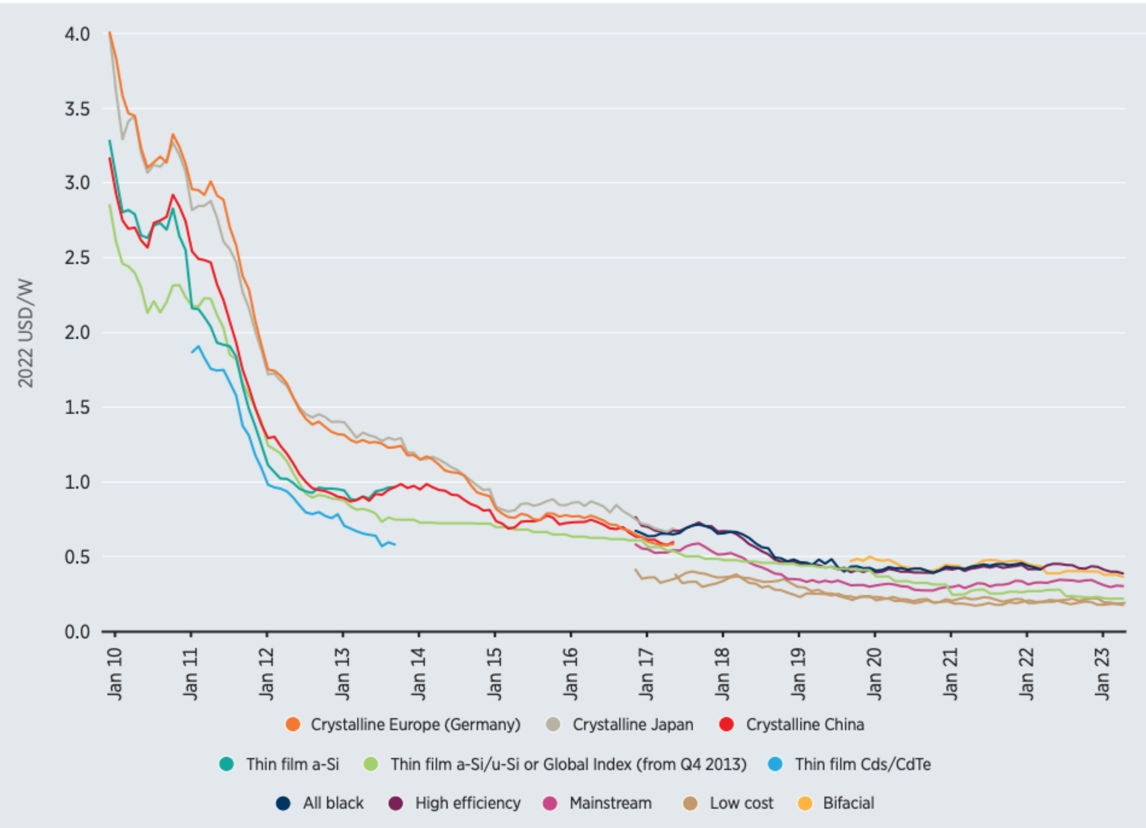


Figure 7: Average monthly solar PV module prices by technology and manufacturing country sold in Europe, 2010 to 2022 (GlobalData (2023); pvXchange (2023); Photon Consulting (2017); IRENA Renewable Cost Database as cited in IRENA, 2022, p. 91).

This price drop has been important for the reduction of the overall cost of solar PV systems. Economies of scale and improved PV technologies will continue this decline by another 50% within 2050 as seen in Figure 8 (DNV, 2021, pp. 13–14; Olson & Bakken, 2019, p. 2).

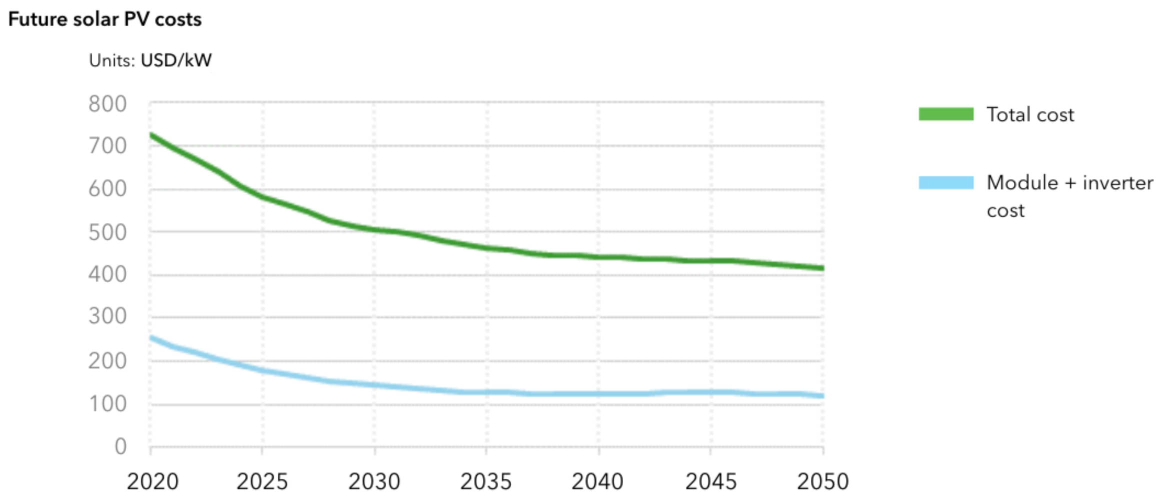


Figure 8: Solar PV hardware costs utility scale, 2020-2050 (DNV, 2021, p. 14).

Key solar PV system cost representing the global solar PV is presented in Table 8 (DNV, 2021, p. 14; IRENA, 2022, p. 96).

Table 8 Key solar PV system cost from IRENA (2022, p. 96) and DNV (2021).

Source	Year	Price
(IRENA, 2022)	2022	876 USD/kW
(DNV, 2021)	2020	730 USD/kW
(DNV, 2021)	2025	590 USD/kW
(DNV, 2021)	2030	500 USD/kW
(DNV, 2021)	2050	400 USD/kW

Hjelme et al. (2023) from Multiconsult have done a tecno-economic calculation for the potential of solar PV systems in Norway. The report shows that the cost of solar PV can vary based on how much installed effect there is. Table 9 shows the cost of solar system regarding installed effect.

Table 9: Cost of PV system regarding installed effect (Hjelme et al., 2023, p. 14).

Installed effect (kWp)	System cost (NOK/kWp)	Inverters (NOK/kWp) (% of system cost)	Annual operation and maintenance (NOK/kWp) (% of system cost)
<50	15 000,00	8,0 %	1,5 %
50-100	10 000,00	7,0 %	1,0 %
100-500	8 000,00	6,0 %	0,5 %
>500	6 000,00	5,0 %	0,5 %

For this thesis, prices of solar PV are based on HOI's offer for their existing solar system, which can be calculated to 8943 NOK/kWp if they had bought it instead of leased it. Here the price of the inverter is included. Typically, the inverters of the solar PV have to be changed every 15 year (Hjelme et al., 2023, p. 14). To compensate for this, the cost of the inverter is apportioned into the costs of the solar PV and BESS. The annual operations and maintenance (O&M) cost is calculated based on the percentage of system cost Hjelme et al. (2023, p. 14) have estimated for annual operation and maintenance shown in Table 9. This led to an O&M cost of 8943 NOK/kWh * 0,5% = 44,67 NOK/kWh. As the solar PVs have a longer technical lifetime than the project lifetime, the replacement cost is irrelevant and is set to zero.

HOI opted to not buy their current solar PVs but instead went with a leasing alternative. They pay 62,08 NOK/kWp monthly, and this price is increased by 1% each year. The deal has a 30-year duration with an option for HOI to buy the PVs after 11 years in operation. In our profitability calculations and simulations, tax and residual value are ignored to enable direct comparisons of the NPCs and present worth with the other configurations. According to informant 3, HOI does not have any tax benefits associated with their current PV system.

5.3.2 BESS prices

Several reports were used to get a picture of the BESS marked prices as shown in Table 10. The BESS-prices are affected by its lifetime, battery capacity, rate of degradation of the battery, power loss, and state of charge-ion (Hannan et al., 2021). The cost of investing in Li-ion BESS has decreased by over 85% from 2012 to 2022 (Kichou et al., 2022, p. 2). Studies indicates that the price of Li-ion BESS will be halved within 2050 (DNV, 2023; Kessels et al., 2017; Murray, 2023).

Table 10: Various collected BESS prices.

Source	Year	Price	Type
(Berg et al., 2021)	2021	400-1200 EUR/kWh	BESS (Li-ion)
(Kessels et al., 2017)	2024	470 EUR/kWh	BESS (Li-ion)
(Kessels et al., 2017)	2040	150 EUR/kWh	BESS (Li-ion)
(DNV, 2023)	2025	300 USD/kWh	BESS (Li-ion)
(DNV, 2023)	2030	200 USD/kWh	BESS (Li-ion)
(DNV, 2023)	2050	130 USD/kWh	BESS (Li-ion)
(Murray, 2023)	2023	180 USD/kWh	BESS (Li-ion)
(Murray, 2023)	2024	148 USD/kWh	BESS (Li-ion)

While prices from Murray (2023) looks at the American market, DNV (2023) has a more international outlook. For this thesis, BESS prices from 2025 to 2049 from DNV (2023, p. 55) is used as shown in Figure 9. Prices in NOK are converted from USD with a currency exchange rate of 10,80 as of 03.04.2024.

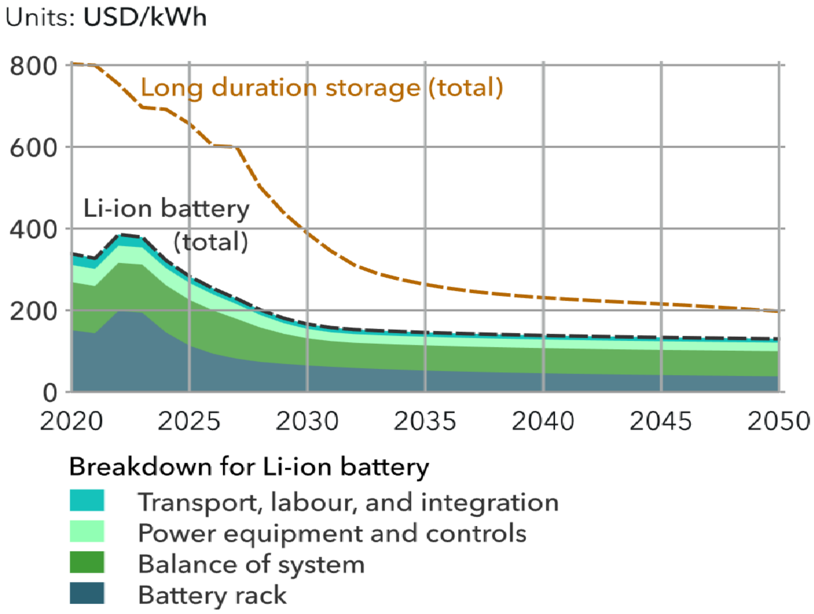


Figure 9: Li-ion BESS prices (black curve) from DNV (DNV, 2023, p. 55).

The chosen replacement cost used in this thesis comes from prices of Li-ion batteries in 2040, since Li-ion batteries have a life cycle of 3000 at 80% depth of discharge (Hannan et al., 2021). The price of Li-ion battery is estimated to be 1621,23 NOK/kWh (converted with the same exchange rate as above) (DNV, 2023, p. 55).

For the operating and maintenance cost of BESS, a percentage between 2,34% and 3,98% of BESS total cost from Lazard's (2018, p. 29) key assumptions for Li-ion batteries in BESS within commercial and industrial sector is used. The O&M cost is estimated to be 3240 NOK/kW * 2,669% = 86,5 NOK/kW.

In Homer GRID, multiplying factors are added to reflect the price changes of BESS. Table 11 shows these factors.

Table 11: Multiplying factors for BESS based on DNV predictions.

Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Multiple factor	1,000	0,900	0,817	0,633	0,600	0,597	0,593	0,590	0,587	0,550	0,547	0,543	0,540
Year	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	
Multiple factor	0,537	0,533	0,530	0,527	0,523	0,520	0,517	0,513	0,510	0,507	0,503	0,500	

5.3.3 Electricity grid tariffs

The factory of HOI is situated in the NO2 bidding area of the Nord Pool power exchange as shown in Figure 10. HOI pays for four different products when they purchase electricity which are summarized in Table 12. In addition to public taxes, and administrations fee to their electricity broker Entelios, they pay a transmission fee to the local distribution system operator, as well as paying for the power itself to the power supplier.

The taxes consist of a consumer electricity tax, the value added tax (VAT), and the Enova tax. Hennig-Olsen has a reduced consumer electricity tax rate, and they have informed us that they in practice always get the VAT in return. Therefore, VAT is not considered when the electricity cost is predicted in the analysis.

The transmission fee consists of three parts. A monthly fixed fee, an energy charge in kr/kWh, and an effect charge which is calculated from the highest average hour per month. The effect fee is higher in the winter months than in the summer.

HOI buys electricity through their power broker Entelios. Entelios can decide when to lock the price and when to buy at spot price. Historically several informants at HOI tells us that about 50% is bought at spot price. However currently this is being done slightly different where Hennig-Olsen has already been able to lock the price for half their electricity demand for the next three years at 67 øre/kWh. This was made possible in 2023 when the Norwegian government reduced the minimum time of such deals from seven to three years (Finansdepartementet, 2023).

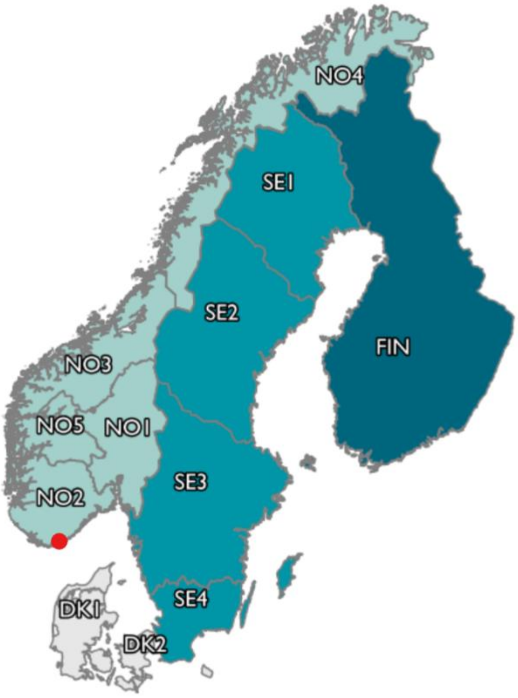


Figure 10: The Nordic bidding zones of the Nord Pool energy exchange (NVE, 2023), and the factory of HOI indicated by the red dot.

Table 12: Electricity grid tariff for HOI in 2024

Public taxes	Electricity consumer tax	0,0058 kr/kWh	Reduced tax rate
	Value added tax	~~25 %~~	Always returned
	Enova tax	800 kr/year	
Entelios fees	Administration fee	0,003 kr/kWh	
	Broker fee	0,003 kr/kWh	
	Invoicing	49 kr/month	
Transmission fee	Fixed fee	500 kr/month	
	Energy rate	0,079 kr/kWh	As of February 2024
	Demand rate	October-March: 96 kr/kW April-September: 30 kr/kW	Based on the highest average hour per month.
Electricity cost	Spot price	Nord Pool NO2 prices	
	Fixed price	0,67 kr/kWh	For 50% of the volume three years ahead.

5.3.4 Electricity price prognosis

As the electricity prices in recent years have been significantly higher than the historical average before the Russian invasion of Ukraine (Statistics Norway, n.d.), and the fact that prices are not expected to return to historical levels in years to come (NOU 2023: 3, pp. 133, 139), we have chosen to rely on future predications of the energy market instead of historical data, as we consider this to be more reliable. Hourly spot prices for an entire year for bidding area NO2 (southern Norway) was pulled from Nord Pool via the web sites of Forbrukerrådet (n.d.). Because of the unusually high prices during the winter months of 2022/2023 the period extracted was adjusted to 1. April 2023 to 31. March 2024 instead of extracting all of 2023. This better represents the typical fluctuations and relative variations in the energy prices. The spot price in this period for NO2 including a moving average curve is shown in Figure C 1 in Appendix C. The fixed price of 67 øre/kWh is considerably lower than the yearly average has been in 2023 and so far in 2024 as of April. However, it is difficult to predict what fixed prices Hennig-Olsen will be able to secure in the long-term, and fixed price deals come with a premium as it reduces risk. We considered averaging the spot prices and the fixed prices when we built the dataset, but we opted against it as we consider it to be too optimistic. Using just the spot price seemed more realistic.

Based on the spot prices collected we have then calculated a yearly average hourly price and the average price variation in a day, week, and month. This yearly average hourly price is then adjusted by a multiplier factor to coincide with one of three energy market scenarios by Statnett (Statnett, 2023a, 2023b), or by The Norwegian Energy Regulatory Authority (NVE, 2023) which in their prognosis are named Low, Basis, and High. Basis represents the most likely scenario. Low and High are based on adjusting several uncertainty factors that leads to the average energy prices becoming persistently higher or lower through the prognosis period. Neither Statnett nor NVE quantifies the probabilities of the different outcomes and emphasizes that the three scenarios are part of the same overall prognosis and outcomes in between these scenarios obviously are possible. As there are several factors that must coincide for the lower or higher outcomes to happen, we can at least argue that it is less and less likely to happen the further away from the Basis scenario we move.

In these prognosis Statnett (2023a, 2023b) and NVE (2023) estimates yearly average hourly prices. NVE does this for the period 2023-2040, while Statnett predicts average hourly prices and the average price variations mentioned above for the period 2023-2028 (Statnett, 2023a) and 2022-2050 (Statnett, 2023b). The price variations are only described in the in the Statnett Basis scenario. Figure 11 shows the three price prognosis scenarios and the price variations from Statnett, while Figure 12 shows the NVE predictions. A conversion rate from EUR to NOK of 11,69 was used, based on the exchange rate 2. April 2024. The calculated multiplier factors for the Statnett and NVE scenarios are available in Appendix C as Table C 1 and Table C 2. An important difference between these reports is that Statnett assumes the entire European energy sector will be greenhouse gas emission free by 2050, while NVE only assumes existing and known measures and therefore does not assume an emission free European energy sector by 2050 (NOU 2023: 3, p. 132). As a consequence, Statnett predicts lower energy prices than NVE. The yearly average hourly prices for the entire period is summarized in Table 13.

Table 13: Yearly average hourly prices for the entire prediction periods of the Statnett and NVE scenarios.

Prognosis (timespan)	**Yearly average hourly prices (øre/kWh)**		
	LOW	**BASIS**	**HIGH**
Statnett (2023-2050)	34,71	45,95	58,71
NVE (2023-2040)	51,00	73,44	98,50
NVE (2023-2050[8])	42,07	64,71	89,75

As the predications by Statnett and NVE has been used recently by both the Energy Commission (NOU 2023: 3) and the Electricity Price Committee (The Electricity Price Committee, 2023) we assess these prognosis to be reliable, although the time-span is very long and of course there is a considerable amount of uncertainty especially towards the end of the prognosis as pointed out by NVE (2023, p. 3) and Statnett (2023b, pp. vii, 4) themselves.

[8] The 2040 price estimates are used for the years 2041 to 2050 as well as NVE do not predict further into the future than 2040.

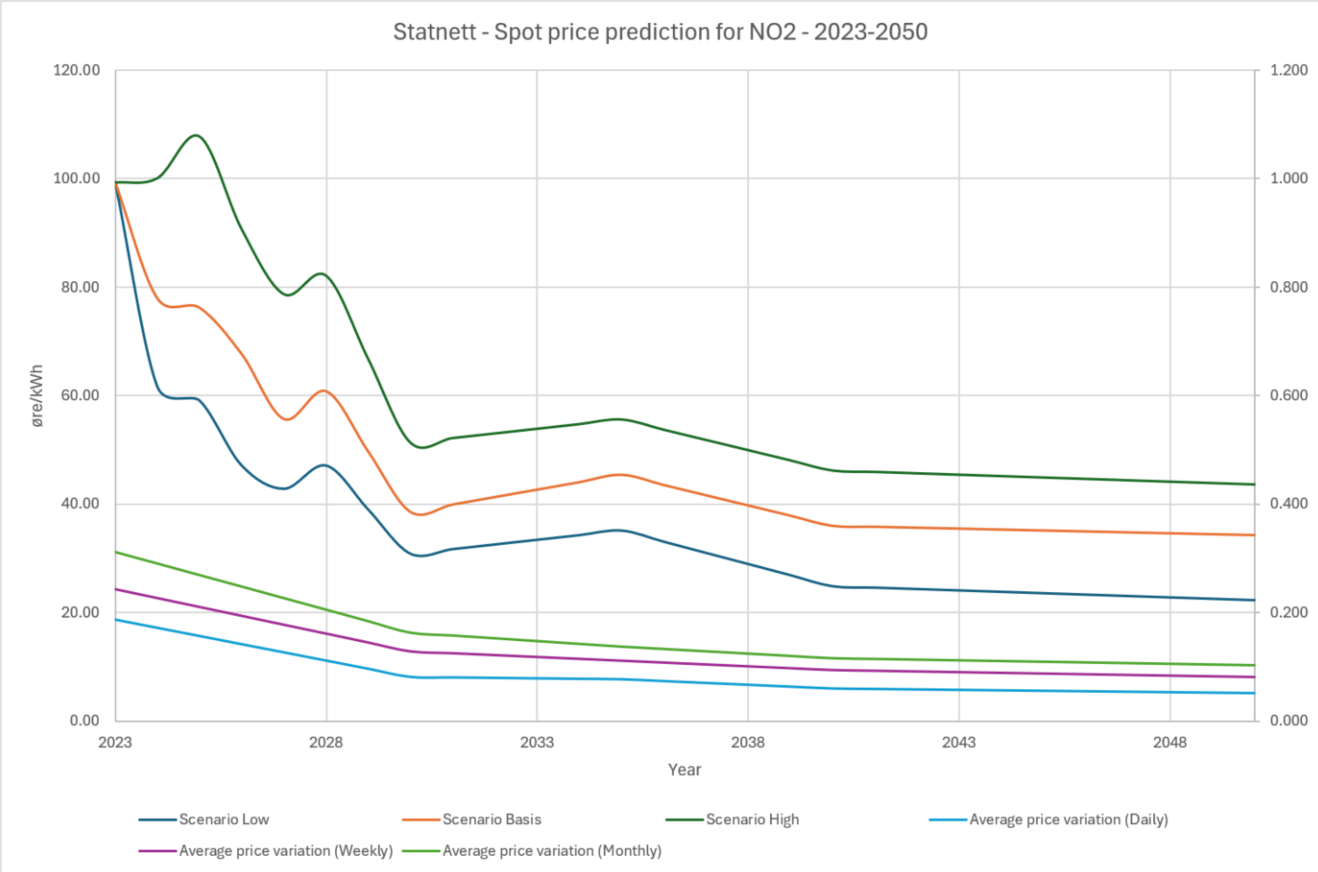


Figure 11: Statnett prediction scenarios for the spot price in NO2, as well as the expected average price variation on a daily, weekly, and monthly basis.

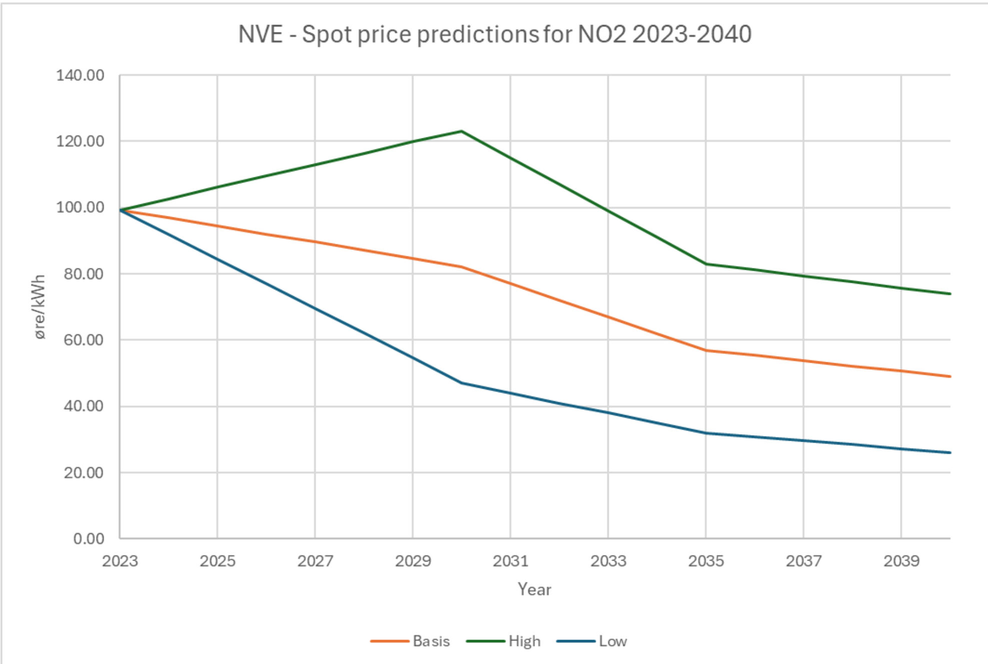


Figure 12: NVE prediction scenarios for the spot price in NO2.

The distribution of the different hourly prices throughout the simulation years can affect the outcome of the simulation. If for instance prices are expected to be more evenly spread out than they are in our data set, then our results may overestimate the profitability of a DES solution because it will be based on higher prices in the upper parts of the distribution. We have therefore compared the distribution of our energy prices dataset with the cumulative distribution function (CDF) figures provided by NVE (2023) for the years 2030 and 2040.

We do not have good CDF curves for the Statnett scenarios, but in the case of NVE we have access to spreadsheets with the actual data points they have used in their report for the years 2030 and 2040 so we can accurately compare. When we plot these CDF over each other in Figure 14 we see that in 2040 we are close to what NVE describes in their report. However, in Figure 13 we see that in 2030 our dataset has a larger spread than what NVE predicts. This means that our upper prices are higher, and our lower prices are cheaper than in the NVE estimates. This may indicate that our results appear more profitable than what the electricity price prognosis predict. The overall average annual hourly price is the same, as this is what we used to estimate the multipliers to generate the simulation dataset to begin with.

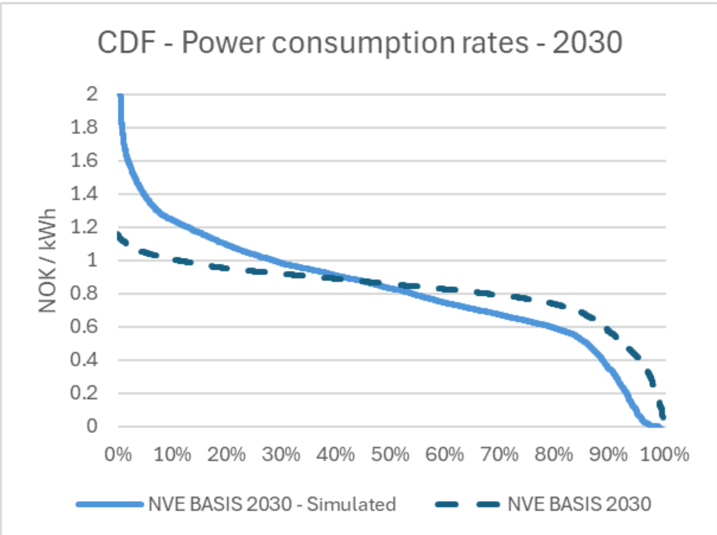


Figure 13: Comparison of consumption rate CDF for 2030 as simulated and as predicted by NVE. Figure based on NVE (2023, p. 66).

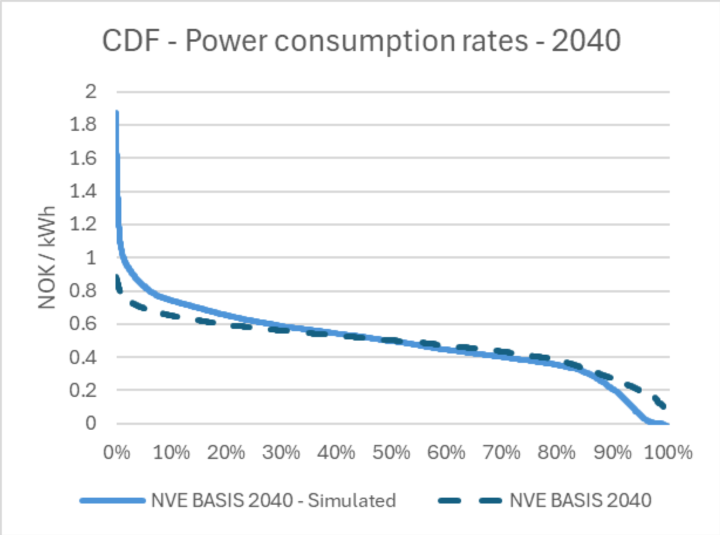


Figure 14: Comparison of consumption rate CDF for 2040 as simulated and as predicted by NVE. Figure based on NVE (2023, p. 66).

To evaluate the accuracy of our version of the Statnett price prognosis we have calculated the average price variation on a daily, weekly, and monthly basis for 2030, 2035, 2040, and 2050 as seen in Figure 15. We compare these values to those provided by Statnett (2023b, p. 63) in Figure 16. What we see is that Statnett predict almost three times higher daily variation and about twice as much weekly and monthly variation in 2030 than we have in our dataset. This discrepancy decreases quite a lot but is considerably higher throughout the simulation period. This may be an indicator that both the demand charges peak shaving calculations and the energy charges time shifting calculations of HOMER can be affected, leading to BESS appearing less profitable. Energy prices in Norway and the rest of Europe are typically lower at nighttime and higher during daytime (NOU 2023: 3, p. 145). This is a consequence of power generation with a higher marginal cost shutting down at nighttime when power consumption is low leaving power plants with a lower marginal cost to supply market demand (The Electricity Price Committee, 2023, p. 24). In the future the price variations will be significantly driven by solar and wind generation conditions, and while solar hours are easy to predict, wind patterns are far mor elusive (The Electricity Price Committee, 2023, p. 24). This will cause more volatile energy prices than the old daytime-nighttime pattern. As the Statnett prognosis is based on the European energy sector becoming emission free in 2050, while the NVE prognosis is not, we can deduce that this effect should be stronger in the Statnett-based datasets than the NVE-based ones. This is due to the fact that the power generators with a higher marginal price are the ones that emit greenhouse gases (NOU 2023: 3, p. 123). This means that there is a greater potential for error, especially in our BESS profitability calculations, when using the Statnett prognosis than when using the NVE prognosis, as we have not manipulated our simulation datasets to replicate these additional volatility effects. We see this as Statnett predicts almost twice as many zero-price hours (hours were consumption is lower than the unregulated power generation in the grid) as NVE does for 2030 (NVE, 2023, p. 56; Statnett, 2023b, p. v). Both parties then predicts that this number will drop significantly in Europe as more flexibility is built into the grid. The zero-price hours prediction by NVE for NO2 however, actually indicates that the number of zero-price hours will be pretty stable through our project lifetime when compared to the 2023-24 period we based our electricity price dataset on. This is a positive argument for the reliability of our inputs in the NVE scenarios but leaves some more room for questioning the Statnett scenarios.

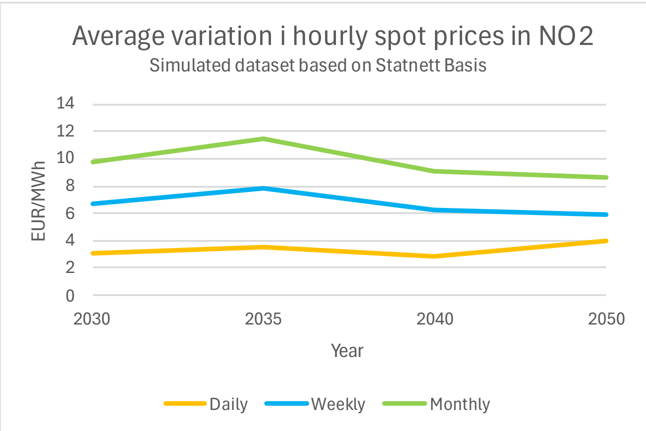


Figure 15: The estimated average price variations in our generated dataset.

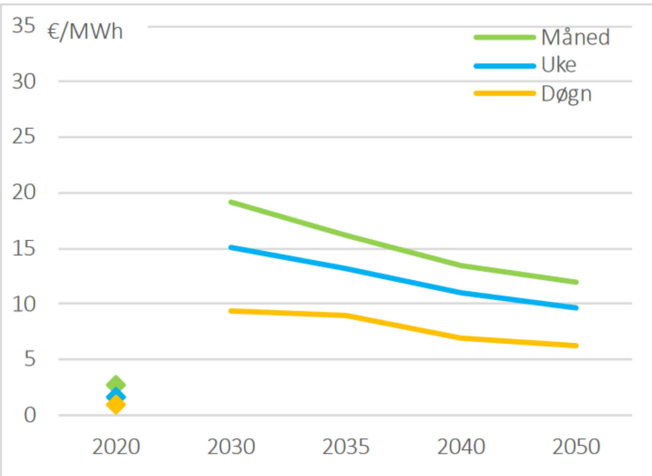


Figure 16: The average price variations predicted by Statnett (Statnett, 2023b, p. 63).

5.4 Delineation of scope

Due to time and processing constraints we had to prioritize what DES solutions could be researched in this thesis. This sub-chapter explains the rationale behind our decisions.

5.4.1 Power generation

We investigated the potential for on-site wind power generation. Exact wind speed data for the factory site in Hannevika was not available. The Norwegian Meteorological Institute has data at 10m above ground for their weather stations at Kjevik and Oksøy lighthouse, and The Norwegian Energy Regulatory Authority has wind maps with 1km x 1km resolution at 50m above ground (Byrkjedal et al., 2009; The Norwegian Meteorological Institute, n.d.-b). Neither of these were considered to have the necessary geographical fidelity to evaluate the potential for wind power generation at the HOI factory due to the surrounding terrain being quite uneven. A considerable data collection effort would be needed to establish how much wind the factory experience through a year. This timeframe was not reconcilable with the time available for the thesis work. A different approach would be to try and model the wind environment at the factory site. We concluded that this would require a level of fluid dynamics competence that neither of the authors possess. Informant 3 also pointed out that the factory has strict height limitations for how high they are allowed to build, with a limit of 15 meters above sea level. This leaves little to no room for installing even quite small vertical-axis wind turbines (VAWT) on the factory roofs. This combined with the fact that the measured wind speeds at the surrounding monitoring stations was relatively low, though still above the cut-in speed for available VAWT solutions which can be at least as low as 4 m/s (Moe et al., 2023, p. 39), and that solar power seemed to have a considerably better potential lead to the conclusion that wind power should not be prioritized for further analysis.

Informants 1, 2, and 3 mentioned that district heating had been investigated by HOI previously. Å Energi operates the district heating in the area and can deliver water at 60°C (Å Energi, 2021). HOI considered this to be too cold and concluded that it would not be profitable to connect with the district heating as there would still be such a major water heating need remaining. Based on the information provided by HOI we chose to not prioritize district heating for further analysis.

We discussed geothermal heating and electricity generation with informant 3. The factory of HOI is largely placed on reclaimed land, where much of the fillings are highly contaminated masses that were dumped there decades ago. During construction of a new road on the waterfront side of the factory HOI faced great challenges and expenses in depositing these masses that at most made up the upper 33 meters of mass above bedrock. According to informant 3 HOI prefers a (pressurized) water temperature of 110 degrees because this fits directly into the existing factory infrastructure. Alternatively (non-pressurized) water temperature of 90 degrees as this is the temperature used for sanitizing production equipment. This is high temperatures for an area that is not tectonically active (Operacz & Chowaniec, 2018; Stensrud, n.d.). For electricity generation a water temperature of at least 70 degrees is required (Gudmundson et al. (1985) as cited in Operacz & Chowaniec, 2018). After our pre-liminary research on the topic we concluded that such a scope was likely unfeasible and therefore chose to not investigate this further. Colder geothermal sources can be used for heating purposes, but we reckoned this would lead to the same conclusion as with the district heating and therefore chose to not investigate this further.

We briefly looked into the possibility of sea water air conditioning (SWAC), based on running a very large pipe into Hannevika, but quickly concluded that this was infeasible due to mainly two reasons. First reason is that Hannevika is a designated anchoring area for ships, and the second reason is that Hannevika is quite shallow which means that the temperature potential needed for SWAC cannot be achieved.

5.4.2 Energy storage

An alternative to BESS is flywheel energy storage system (FESS). The FESS uses an electro-mechanical device to store kinetic energy as opposed to battery systems which are electrochemical and store electrical energy (Li & Palazzolo, 2022; Mousavi G et al., 2017). FESS can be a good alternative to BESS as they are *"[…] effective within frequent charge and discharge at a large number of cycles"*, and therefore, it could be an interesting storage system to combine with solar PV systems. However, some of the disadvantages of FESS are the cost of the system and scaling. Compared to batteries, FESS can cost up to 1,4 times more (Li &

Palazzolo, 2022, p. 1; Sears, 2004 as cited in Mousavi G et al., 2017). In addition, increasing the storage size is difficult (Mousavi G et al., 2017). Because FESS costs significantly more than BESS, and our preliminary HOMER analysis indicated poor profitability for BESS, we chose to not simulate FESS, and instead prioritize these processing resources for other DES configurations.

There is a potential in thermal energy storage solutions (as opposed to electrical energy storage) that remains unexplored. HOI has some thermal storage today in the form of an ice-water reservoir, where water is cooled at night and used during the day, and a "buffer pool" as part of the heat pump system. In addition to this the freezer storage units also accumulate large amounts of thermal energy that is being exploited to reduce energy and effect demand to achieve the effects of peak shaving, valley filling, and time shifting. The idea of accumulating warm water at times where the cost of energy is low might be profitable but requires more research to conclude. HOI has very little warm water accumulation capabilities today, but informant 3 pointed out the potential for time shifting in such a solution. We were not able to investigate this properly as the potential was uncovered rather late in our research process. It would require quantitative data collection of energy consumption within the heating central and factory using additional meters and sensors in addition to the ones installed today that measure total consumption. The analysis of such a solution might also have required knowledge of thermodynamics beyond what the authors possess. Due to these reasons, and simply a lack of time, thermal storage was not prioritized further but is definitely an interesting future research topic.

5.5 Energy production and utility

The remaining sub-chapters of this chapter presents and explains results from the HOMER Grid simulations. We have simulated a generic type of solar PVs in HOMER Grid based on the type that HOI has installed today. For BESS we have used a generic BESS that HOMER Grid suggests from its database. This BESS is given the constraint that it may not discharge below 20% as this is preferred to maintain battery health throughout the technical lifetime of 15 years. Since every configuration with solar PV has the same size, 375kWp, they produce the same amount of energy throughout a year in every simulation. In addition, the same energy load is used for every simulation. Figure 17 shows the amount of energy consumed by the transformer in a random simulation year and how much of that energy is generated from solar PVs in the scenarios that include PVs. In scenarios without PVs the total consumption is the same, but all energy is purchased from the grid. Figure 18 shows the pattern of electricity generated by solar PVs as power output throughout a year for every simulation with solar PVs. As expected, generation increases during summer due to longer days and stronger solar radiation.

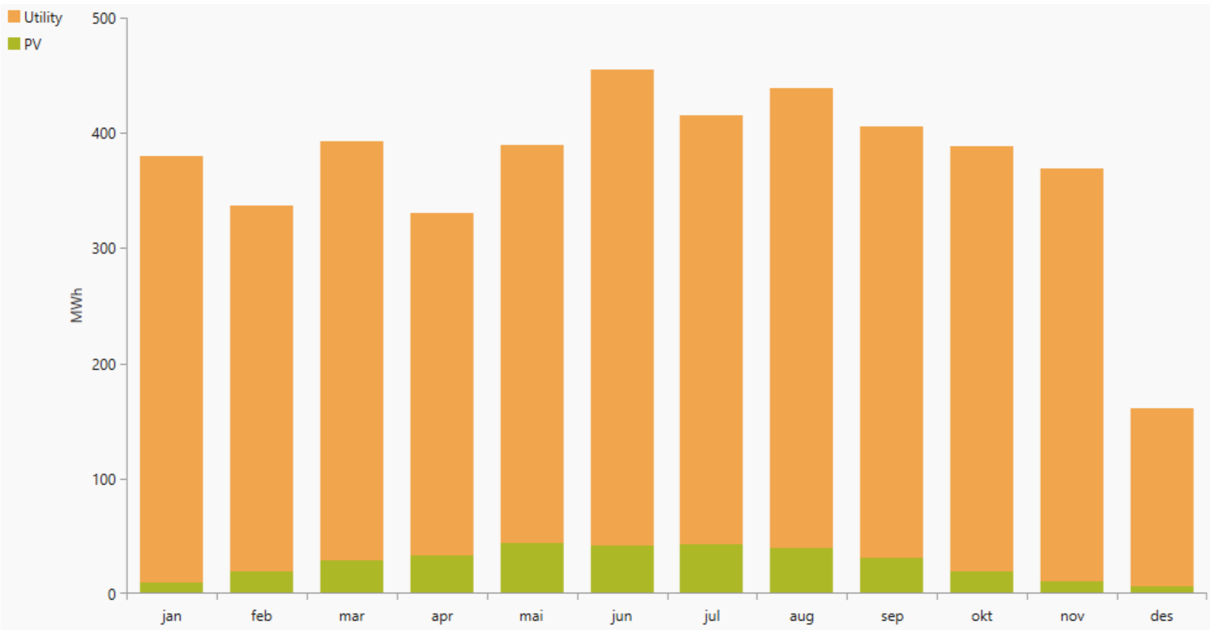


Figure 17: Example of a month of electricity consumption from HOMER simulation. The vast majority of electricity is bought from the grid. The exact distribution of consumption is not identical for each simulation year in HOMER as there is some degree of randomization between the years. Overall consumption is equal each year varies.

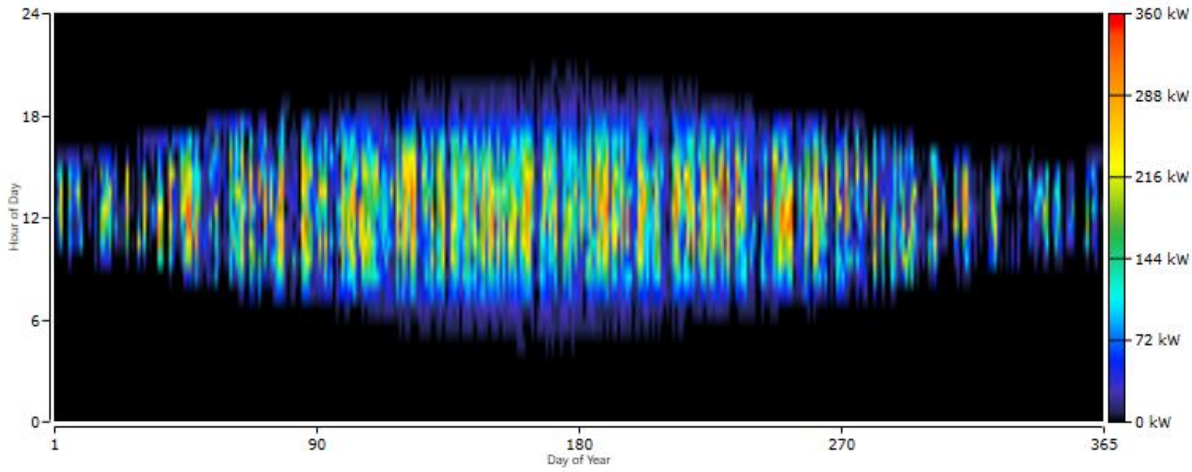


Figure 18: Distribution map showing the power output by the 375 kWp PVs in a HOMER simulation year.

5.6 Present worth comparisons

A comparison of the different configurations and prognosis' present worth is presented in this sub-chapter. As the discount rate increases, the profitability diminishes for all configurations compared to the base case. For all the 2024 scenarios, investing in BESS is not profitable.

The comparison of present worth at a discount rate of 3,566% in the 2024 scenarios is shown in Figure 19. The results show that with a risk-free discount rate, PV Buy and PV Buy + BESS becomes profitable under several prognoses. Although PV Buy have a positive present worth of NOK 131 720 at Statnett High, the margins are quite low when we compare them to the necessary CAPEX of NOK 3,35M. PV Leasing on the other hand is only profitable at NVE High.

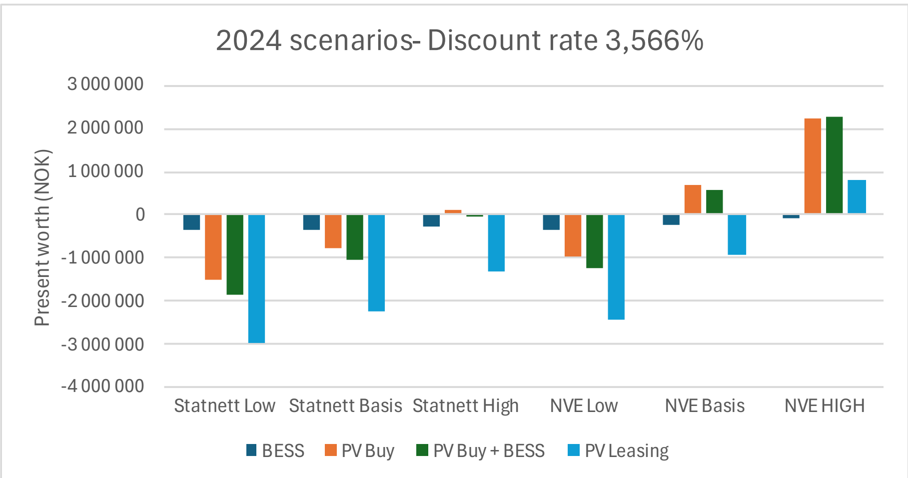


Figure 19: Present worth comparison at 2024 scenarios with a discount rate of 3,566%.

For discount rates of 6% to 12%, configurations only become profitable in 2024 given the NVE High prognosis as shown in Figure 20, Figure 21, Figure 22, and Figure 23. At a discount rate of 8% PV Leasing becomes more profitable than PV Buy. As the discount rate increases from 8% to 10% PV Buy and PV Buy + BESS becomes unprofitable. At a discount rate of 10% and 12% PV Leasing is the only profitable configuration.

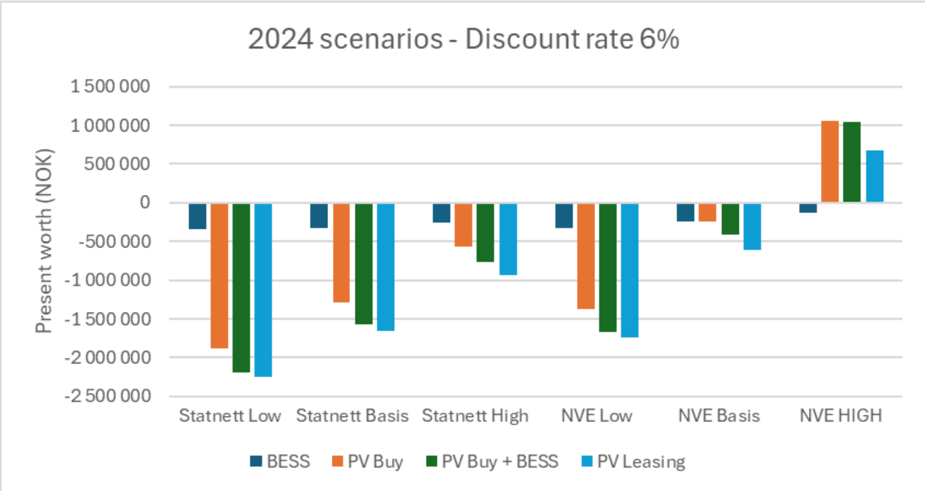


Figure 20: Present worth comparison at 2024 scenarios with a discount rate of 6%.

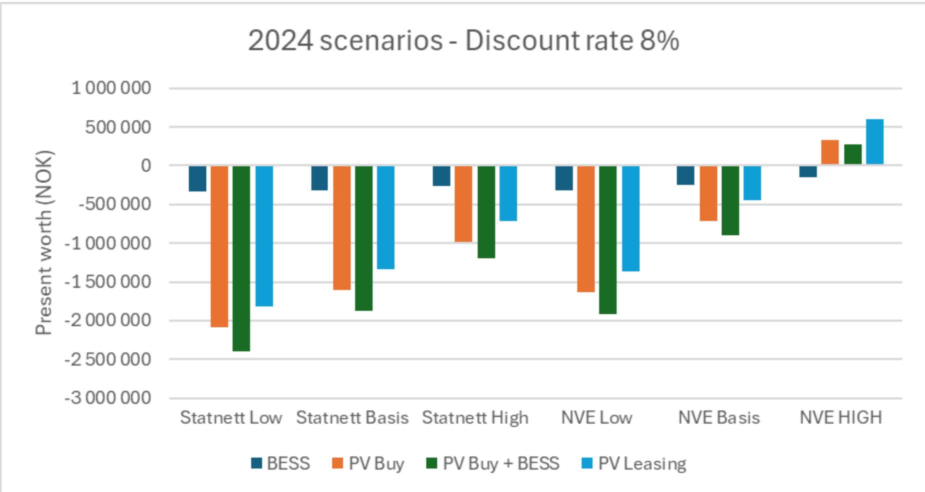


Figure 21: Present worth comparison at 2024 scenarios with a discount rate of 8%.

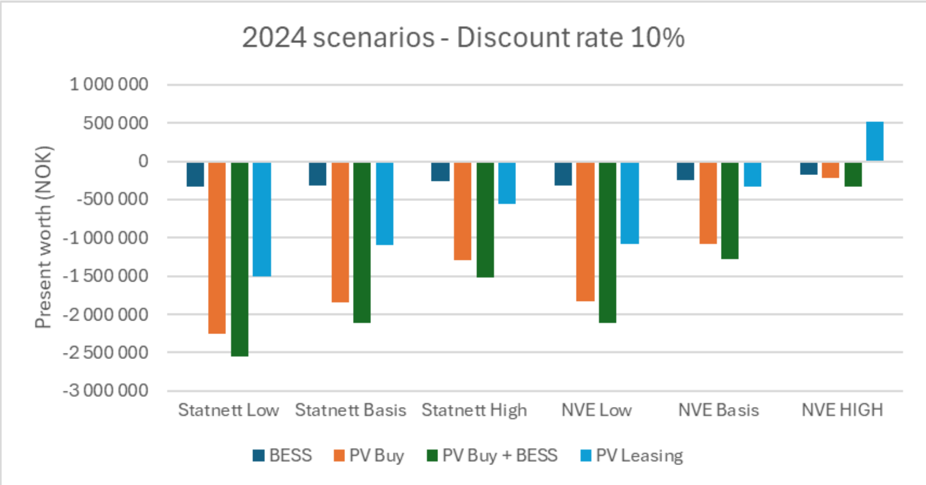


Figure 22: Present worth comparison at 2024 scenarios with a discount rate of 10%.

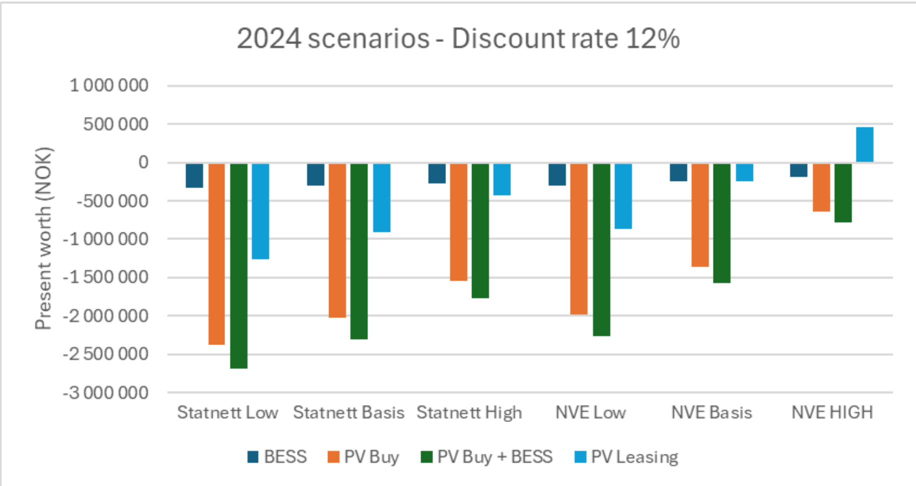


Figure 23: Present worth comparison at 2024 scenarios with a discount rate of 12%.

For the 2030 scenarios, Figure 24, Figure 25, Figure 26, Figure 27, and Figure 28 show that the different configurations get a greater present worth over the different prognoses compared to the 2024 scenarios. Nevertheless, BESS still does not become profitable alone. In addition, at a risk-free discount rate in 2030, Statnett Low and NVE Low still do not provide profitable configurations.

Given NVE High, the present worth, ROI and discounted payback is better compared to the 2024 scenarios. The results do also show that PV Buy + BESS is more profitable than PV Buy at a discount rate of 3,566% to 8% at NVE High. At a discount rate of 10% and 12% however adding BESS to the PV configuration reduces the overall profitability of the configuration.

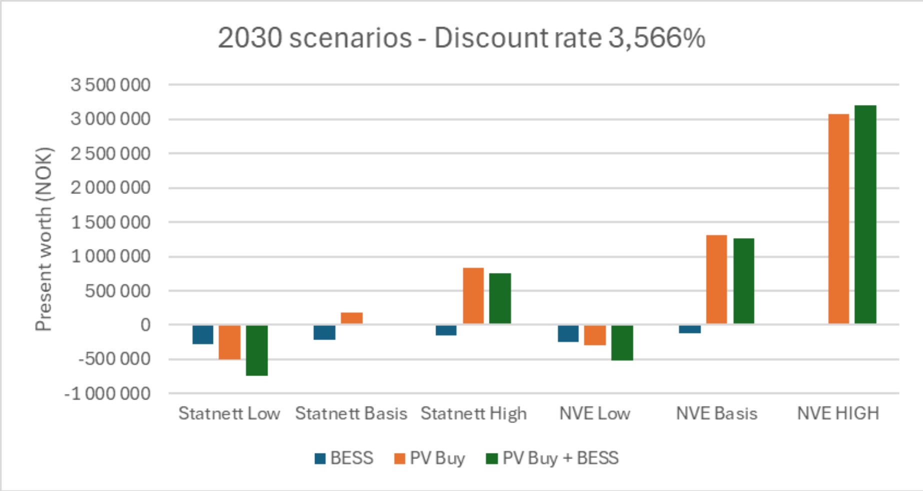


Figure 24: Present worth comparison at 2030 scenarios with a discount rate of 3,566%.

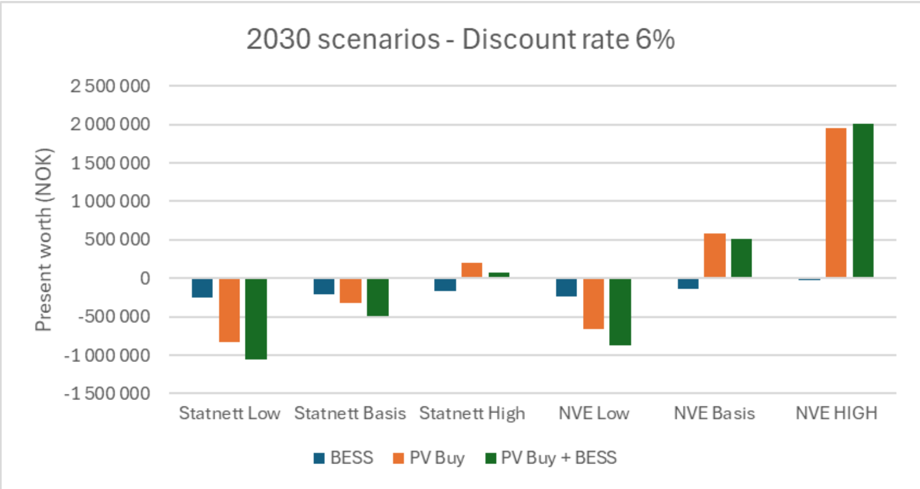


Figure 25: Present worth comparison at 2030 scenarios with a discount rate of 6%.

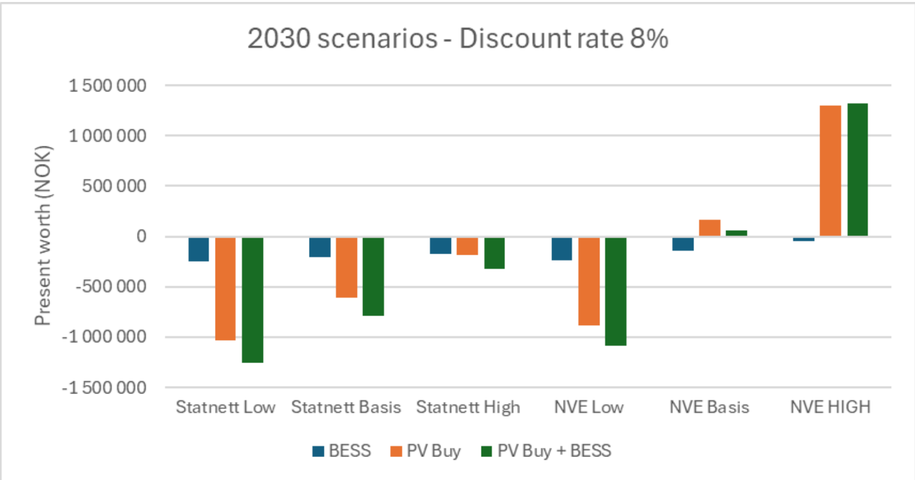


Figure 26: Present worth comparison at 2030 scenarios with a discount rate of 8%.

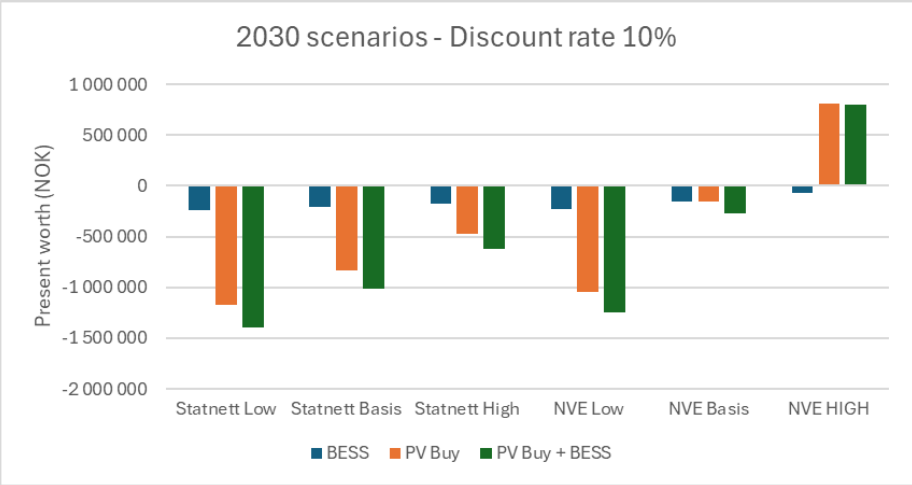


Figure 27: Present worth comparison at 2030 scenarios with a discount rate of 10%.

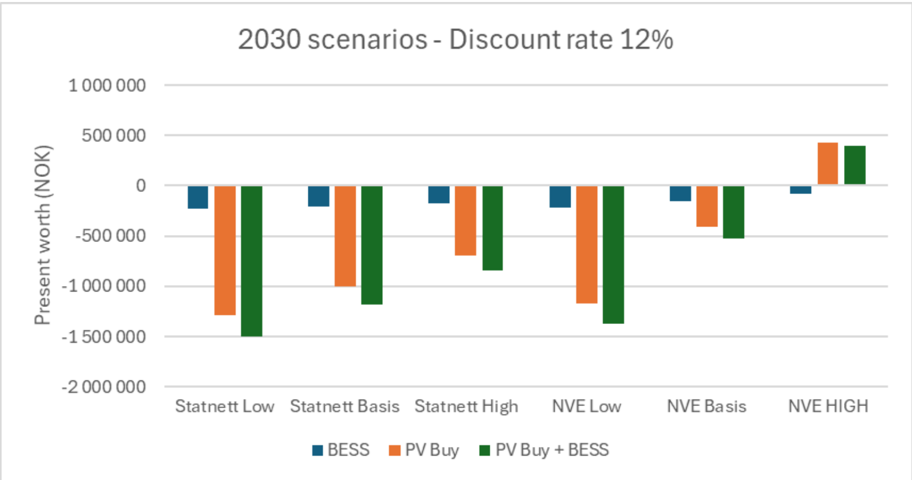


Figure 28: Present worth comparison at 2030 scenarios with a discount rate of 12%.

5.7 Sensitivity

The simulations with sensitivity analyses show how much the component prices must change to at least break even, given the different prognoses of 2024. With a sensitivity of 1, the configuration has a positive margin at the cost described in Table 3. At what cost this margin disappears was not investigated, as simulations with sensitivity values above 1 was not prioritized. The simulation results of the sensitivity analysis is presented in Figure 29, Figure 30, Figure 31, Figure 32 and Figure 33, where they are sorted by discount rates.

In Statnett Low, BESS prices did not break even, even when the sensitivity was set to 0.01. Running lower sensitivity values than this was not prioritized as it was assessed as irrelevant. Therefore, BESS sensitivity values are not provided for Statnett Low simulations.

Applying sensitivities for BESS replacement cost in addition to BESS capital cost was done for Statnett Basis. These replacement cost sensitivities did not significantly affect the profitability of BESS. Therefore, running these sensitivity analyses for other scenarios were not prioritized as it was very time consuming due to high computer processing load when combining multiple sensitivities. Therefore, sensitivity values for BESS replacement cost combined with BESS capital cost is only provided for the Statnett Basis simulations. These values are referred to as "BESS Replacement" in the figures.

The graphs shown in this sub-chapter appears to be equally steep for BESS, PV Buy and PV Leasing, with just some minor differences. This indicates these configurations are equally sensitive to the prognoses. However, there is a significant difference in how much reduction the different configurations need to break even compared to each other. At a discount rate of 8%, the simulations imply the BESS prices must be reduced 90% for Statnett Basis and NVE Low, while 70% for NVE Basis and about 45% for NVE High for the BESS configuration to break even. At a discount rate of 10%, prices of PV Buy should be reduced by 45% at NVE Basis versus 10% for PV Leasing, while with a discount rate of 12%, PV Buy should be reduced by 50% at NVE Basis versus 10% for PV Leasing.

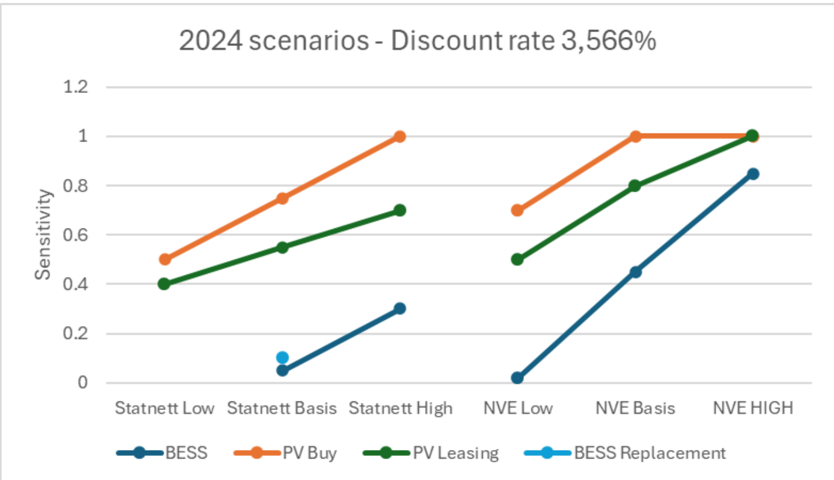


Figure 29: Sensitivities comparison at 2024 scenarios with a discount rate of 3,566%.

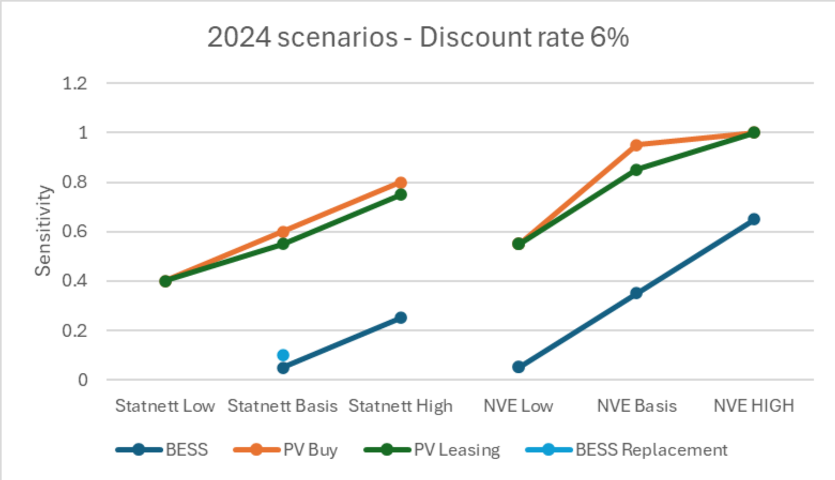


Figure 30: Sensitivities comparison at 2024 scenarios with a discount rate of 6%.

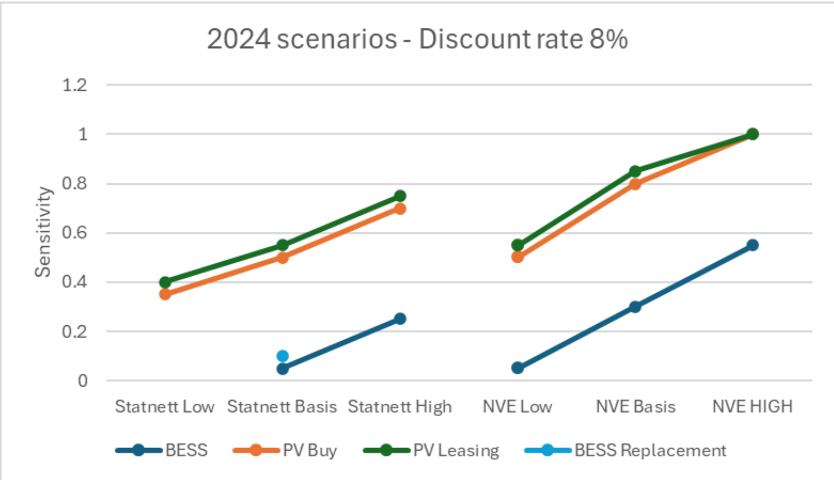


Figure 31: Sensitivities comparison at 2024 scenarios with a discount rate of 8%.

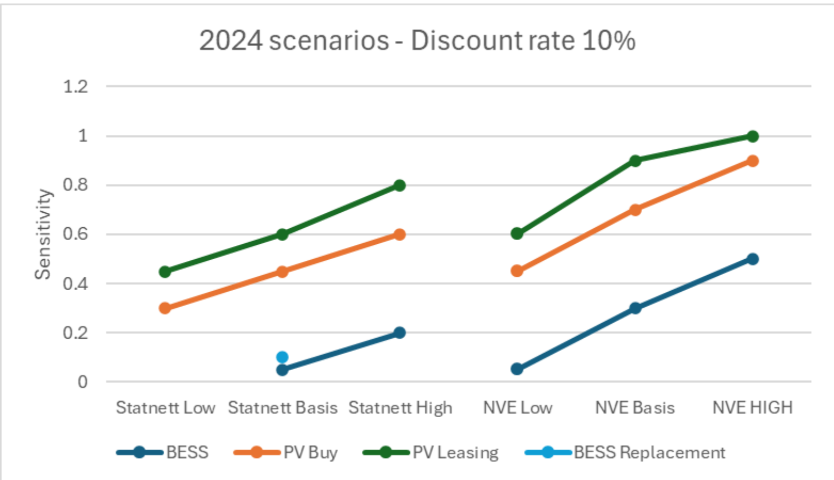


Figure 32: Sensitivities comparison at 2024 scenarios with a discount rate of 10%.

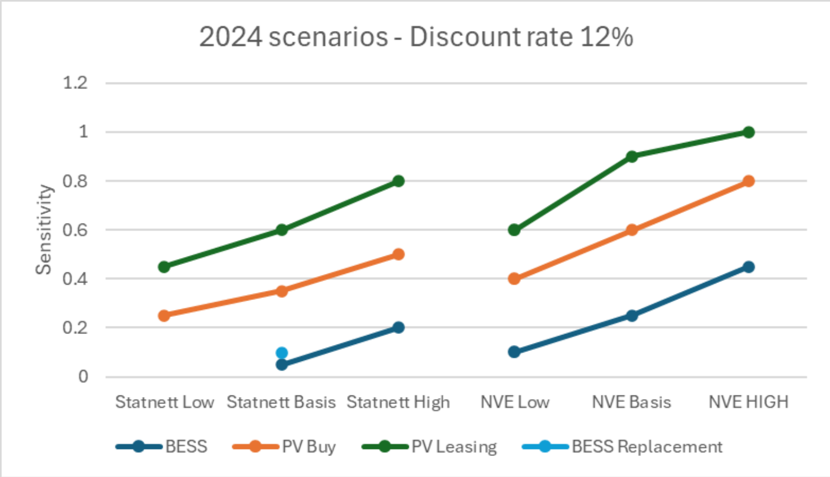


Figure 33: Sensitivities comparison at 2024 scenarios with a discount rate of 12%.

As the discount rate increases the necessary cost reduction for buying PVs increases rapidly, while the necessary cost reduction for leasing PVs remains more stable, and actually decreases slightly. This indicates that the prices of buying PVs are more sensitive to changes in discount rates than the prices of leasing. At a discount rate above about 8% buying PVs requires a greater cost reduction to break even than leasing, while below this buying requires less reduction. This can be seen in Figure 34.

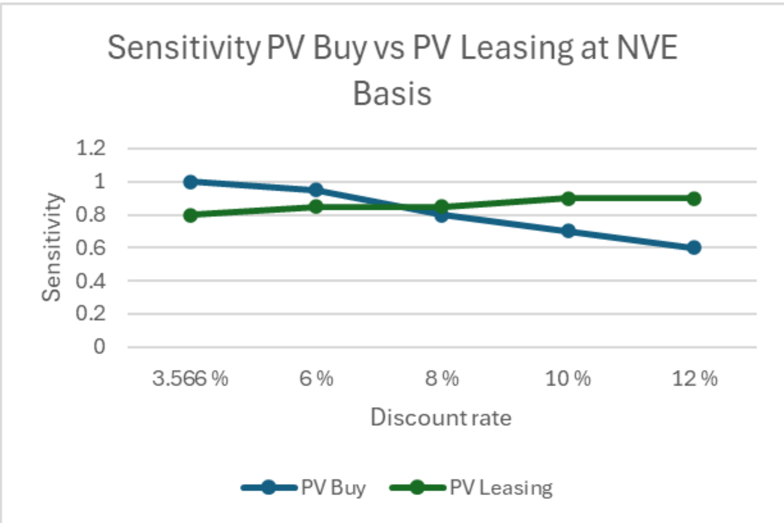


Figure 34: Sensitivity comparison of PV Buy and PV Leasing at NVE Basis.

5.8 DES sizing, peak shaving, and time shifting

To investigate the effect of DES component sizing, as well as to see what DES component affects what part of the energy bill (demand charge vs. energy charge), we ran Scenario 11 (N-H-24-1) with additional BESS and PV component sizes at a discount rate of 3,566%. We then compared the change in demand charges and energy charges, as well as total energy cost, to the necessary CAPEX for each configuration. Additional tables are available in Appendix A.

5.8.1 Demand charges and peak shaving

Table 14 below shows that solar PVs have no real peak shaving effect on this transformer. In the winter months we see that BESS achieves a profitable peak shaving effect. However, in the summer months when the demand rate is less than a third of the winter demand rate, the profitability of BESS disappears, and only gets worse as you increase the BESS size. On the other hand, when BESS is combined with PVs, the reduction of the demand charge relative to CAPEX actually improves up to a BESS size of 1500 kWh, but it is still not profitable though.

Table 14: Relative improvement in demand charge per CAPEX compared to Base case (1 = Break even).

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	3.67	1.55	1.15	1.01	0.87	0.74	0.66	0.06	0.06	0.06	0.11
February	1.00	3.07	1.78	1.16	0.93	0.80	0.72	0.68	0.00	0.00	0.00	0.07
March	1.00	3.93	2.01	1.33	1.07	0.91	0.82	0.77	0.00	0.00	0.00	0.11
April	1.00	1.44	0.73	0.39	0.35	0.27	0.22	0.20	0.01	0.01	0.01	0.04
May	1.00	0.74	0.34	0.26	0.19	0.16	0.14	0.13	0.16	0.09	0.06	0.07
June	1.00	0.42	0.26	0.18	0.16	0.14	0.10	0.08	0.10	0.07	0.05	0.05
July	1.00	0.29	0.25	0.21	0.18	0.14	0.15	0.14	0.02	0.02	0.02	0.05
August	1.00	0.50	0.27	0.24	0.21	0.19	0.00	0.00	0.00	0.00	0.00	0.03
September	1.00	0.50	0.26	0.21	0.18	0.14	0.00	0.00	0.00	0.00	0.00	0.04
October	1.00	0.55	0.53	0.51	0.48	0.46	0.45	0.45	0.00	0.00	0.00	0.04
November	1.00	3.40	1.59	1.01	0.84	0.74	0.68	0.64	0.09	0.04	0.02	0.09
December	1.00	4.53	1.76	1.23	1.04	0.93	0.86	0.81	0.04	0.04	0.04	0.14

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	0.39	0.53	0.58	0.61	0.59	0.54	0.49
February	0.27	0.58	0.62	0.59	0.56	0.55	0.52
March	0.42	0.70	0.72	0.67	0.64	0.61	0.59
April	0.15	0.26	0.29	0.26	0.24	0.21	0.20
May	0.17	0.24	0.24	0.22	0.19	0.17	0.15
June	0.15	0.19	0.18	0.18	0.18	0.14	0.13
July	0.11	0.19	0.19	0.18	0.17	0.16	0.16
August	0.10	0.19	0.18	0.17	0.17	0.16	0.15
September	0.12	0.18	0.16	0.17	0.14	0.08	0.00
October	0.14	0.34	0.39	0.40	0.40	0.40	0.40
November	0.32	0.54	0.52	0.51	0.50	0.48	0.48
December	0.44	0.59	0.62	0.62	0.62	0.61	0.61

All PVs configuration D is 375 kWp

5.8.2 Energy charges

From Table 15 we see that BESS has very little to contribute in order to reduce the energy charge in this case. The PVs on the other hand are a great way of achieving this effect, even if quadrupled in size. We also see that PVs alone perform better than PVs combined with BESS.

Table 15: Relative improvement in energy charge per CAPEX compared to Base case (1 = Break even).

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	0.14	0.14	0.11	0.07	0.05	0.06	0.05	0.84	0.83	0.80	0.73
February	1.00	0.08	0.04	0.03	0.00	-0.02	-0.04	-0.06	1.55	1.53	1.45	1.19
March	1.00	0.15	0.12	0.11	0.07	0.02	-0.04	-0.09	2.66	2.65	2.58	2.21
April	1.00	0.38	0.28	0.25	0.16	0.14	0.14	0.11	3.04	2.98	2.81	2.44
May	1.00	0.38	0.39	0.28	0.23	0.16	0.13	0.10	3.98	3.93	3.72	3.22
June	1.00	0.24	0.22	0.18	0.14	0.12	0.13	0.12	3.21	3.21	3.14	2.89
July	1.00	0.01	-0.06	-0.06	-0.04	-0.04	-0.06	-0.06	3.68	3.66	3.42	2.99
August	1.00	0.28	0.16	0.11	0.11	0.10	0.25	0.24	2.59	2.57	2.41	2.10
September	1.00	0.45	0.33	0.23	0.15	0.11	0.23	0.21	3.27	3.24	2.97	2.50
October	1.00	0.13	0.11	0.08	0.04	0.02	-0.04	-0.06	1.76	1.76	1.72	1.53
November	1.00	0.17	0.15	0.08	0.06	0.05	0.03	0.01	0.86	0.86	0.85	0.77
December	1.00	0.14	0.14	0.16	0.14	0.09	0.06	0.04	0.53	0.53	0.47	0.37

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	0.77	0.61	0.48	0.39	0.32	0.29	0.26
February	1.41	1.05	0.79	0.63	0.51	0.42	0.36
March	2.43	1.84	1.41	1.14	0.95	0.80	0.68
April	2.76	2.14	1.64	1.32	1.11	0.96	0.84
May	3.63	2.78	2.13	1.71	1.42	1.23	1.08
June	2.94	2.22	1.72	1.38	1.15	1.01	0.89
July	3.35	2.46	1.86	1.49	1.23	1.04	0.90
August	2.38	1.78	1.39	1.15	0.97	0.83	0.73
September	3.00	2.29	1.76	1.39	1.15	1.04	0.98
October	1.62	1.22	0.93	0.74	0.61	0.51	0.41
November	0.80	0.63	0.48	0.40	0.33	0.28	0.23
December	0.50	0.41	0.35	0.29	0.24	0.20	0.16

All PVs configuration D is 375 kWp

5.8.3 Total energy cost

Table 16 shows the relative improvement on the total energy cost. We see that the demand charge reduction from the BESS in the winter months greatly reduces the overall energy cost, but then in the summer months becomes unprofitable. The PVs contribute more in summer when days are longer and the sun is higher. The combination of PVs and BESS spreads the cost reduction more evenly throughout the year.

Table 16: Relative improvement in total energy cost per CAPEX compared to Base case (1 = Break even).

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	3.82	1.69	1.26	1.07	0.93	0.80	0.70	0.90	0.89	0.86	0.84
February	1.00	3.15	1.82	1.18	0.93	0.78	0.68	0.62	1.55	1.53	1.45	1.26
March	1.00	4.09	2.13	1.44	1.14	0.93	0.79	0.67	2.66	2.65	2.58	2.32
April	1.00	1.83	1.02	0.64	0.51	0.41	0.35	0.31	3.04	2.99	2.82	2.48
May	1.00	1.13	0.73	0.54	0.41	0.32	0.27	0.23	4.14	4.02	3.77	3.28
June	1.00	0.65	0.49	0.36	0.30	0.26	0.23	0.20	3.31	3.28	3.19	2.95
July	1.00	0.31	0.18	0.15	0.14	0.11	0.09	0.08	3.70	3.68	3.44	3.04
August	1.00	0.78	0.43	0.35	0.33	0.30	0.25	0.23	2.59	2.57	2.41	2.14
September	1.00	0.95	0.59	0.44	0.33	0.25	0.22	0.21	3.27	3.24	2.97	2.54
October	1.00	0.68	0.64	0.60	0.52	0.48	0.41	0.39	1.76	1.76	1.72	1.57
November	1.00	3.57	1.73	1.10	0.90	0.79	0.71	0.65	0.94	0.90	0.87	0.86
December	1.00	4.66	1.90	1.38	1.17	1.02	0.92	0.85	0.58	0.58	0.51	0.50

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	1.17	1.14	1.06	1.00	0.92	0.83	0.75
February	1.68	1.64	1.42	1.22	1.08	0.97	0.88
March	2.85	2.54	2.13	1.81	1.59	1.41	1.27
April	2.91	2.39	1.93	1.58	1.34	1.17	1.03
May	3.80	3.02	2.37	1.93	1.62	1.40	1.23
June	3.09	2.41	1.90	1.57	1.33	1.15	1.01
July	3.46	2.65	2.04	1.66	1.40	1.21	1.07
August	2.48	1.96	1.57	1.32	1.14	0.99	0.88
September	3.12	2.46	1.91	1.55	1.30	1.11	0.98
October	1.76	1.57	1.33	1.14	1.01	0.91	0.81
November	1.12	1.16	1.00	0.90	0.83	0.76	0.72
December	0.94	1.00	0.97	0.91	0.86	0.81	0.77

All PVs configuration D is 375 kWp

5.9 Cash flows - Buying vs. leasing solar PVs

Figure 35 illustrates, using scenario 11 (N-H-24-1), how leasing is in nominal terms more expensive than buying PVs in our case. For each year the figure shows the cumulative cash flow at that point. In other words, it takes the cash flow of that year and adds the cash flow from all previous years. When we graph the cumulative discounted cash flows in Figure 36 we see that the leasing cash flows is affected far more than the buying cash flows. This is due to the annual payments in the leasing scenarios being much greater than in the buying case, and therefore the effect of discounting the cash flow is greater. As a result of this we see that at the higher discount rates of 8-12% leasing becomes more profitable than buying, while at the lower discount rates of 3,566% and 6% buying is the most profitable. This however does not tell the full story as it only describes which has the lowest cost of leasing and buying. To see if an option is profitable, we can compare it to the total discounted energy cost savings. This is done by comparing the energy costs of the base case and the PV configurations for each discount rate. When this is plotted in Figure 36 we see that if the cumulative discounted cash flow curve of buying or leasing PVs are above the total energy cost savings curve, it means the configuration is profitable. Figures showing annual cash flows for both energy purchase and PV costs are available in Appendix A chapter A.11.3.

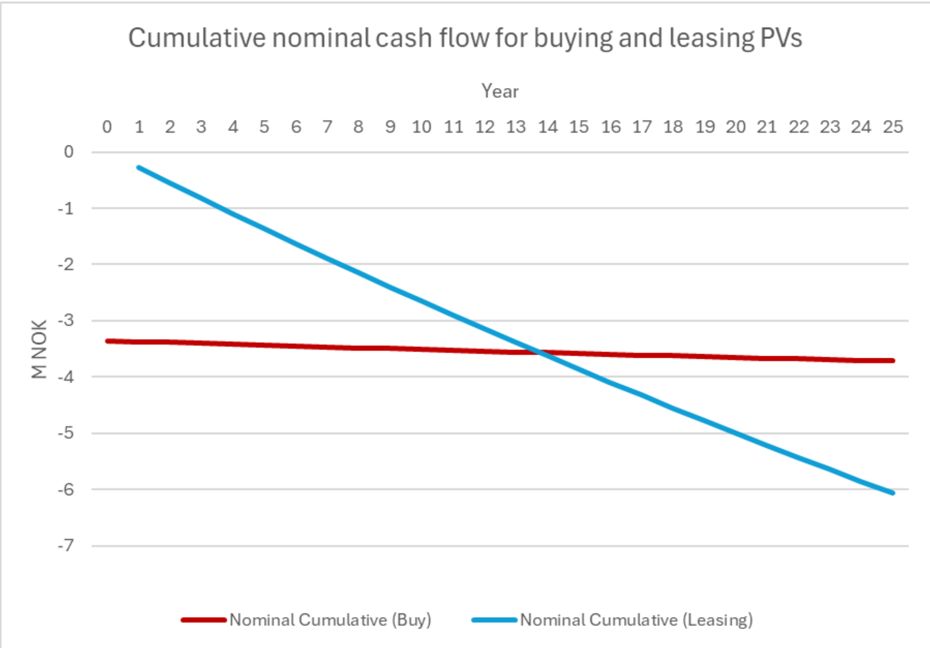


Figure 35: Cumulative nominal cash flow for buying and leasing PVs in scenario 11 (N-H-24-1).

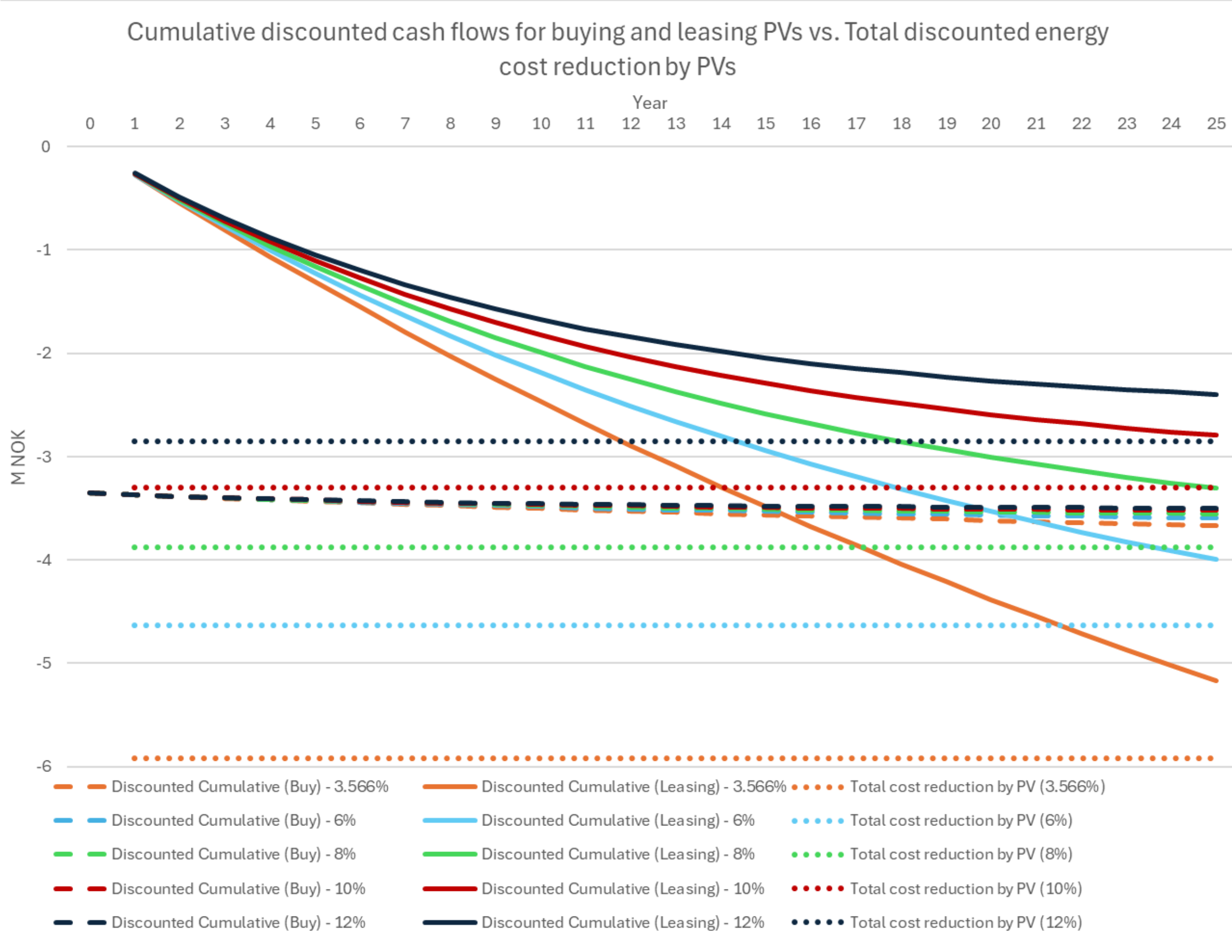


Figure 36: Cumulative discounted cash flows for buying and leasing PVs, compared to the total discounted energy cost reduction offered by the PVs in scenario 11 (N-H-24-1).

6 Discussion

In this chapter we will discuss the analysis results and use these to answer the research questions. We will try to understand what the present worth results tell us, what we can interpret from the sensitivity analysis, how various cost reduction effects are achieved using DES, and how leasing compares to buying PVs before we explicitly answer the research questions. Finally, we briefly discuss the potential for generalizing our results.

6.1 Present worth comparisons

With a higher discount rate, it becomes harder for the configurations to beat the base case. Even though a lower discount rate made some of the configurations more profitable, a lower discount rate may not have reflected risk associated with the configurations and scenarios. There is uncertainty of which prognosis that is most likely to happen, or if any of them will happen at all. In addition, one cannot exclude occurrences of potential failures of the DES.

Given the discount rate used on average in the industrial sector, the findings of 6% and 8% may be a more accurate picture of the investment. With this, NVE High is the only prognosis that indicates leasing solar PVs and buying solar PVs with or without BESS is profitable at the 2024 scenarios. All though the present worth is positive, a total margin of NOK 250k to 1 million over a 25-year investment is relatively low. This can be seen when comparing the annualized ROI with the risk-free rate, as the ROI is only 0,023% higher for PV Buy and 0,034% for PV Buy + BESS. In addition, the energy market must move in a way the prognosis of NVE High suggests. Given a discount rate of 9%, which is in the higher end of discount rates typically used for solar PV investments, one could end up with a scenario where PV Buy and PV Buy + BESS are not profitable at any prognosis. There seems to be a crossing point for this between 8% and 10%. All though PV Leasing is still profitable at a discount rate of 10% and 12%, the margins are still very low. This profitability also relies on the future energy prices coinciding very closely with the NVE High scenario, which is less likely to occur as it is affected by so many factors that must coincide for that scenario to become true, as previously mentioned. The combination of low margins and the reliance on a more unlikely energy price prognosis makes these investment options appear very risky. Ignoring how risky the configurations are, overall, at a discount rate of 8% there is a possibility of gaining a reduction in energy costs by NOK 250k to 500k given the configuration of either PV Buy, PV Buy + BESS or PV Leasing.

On the other hand, in the 2030 scenarios the profitability picture looks better. PV Buy and PV Buy + BESS returns positive margins in the Statnett High, NVE Basis, and NVE High scenarios. Only in the NVE High scenario do we see considerable positive margins at the higher discount rates. PV Buy comes out with a discounted payback period of 8,3 to 9,4 years, ROI of 7,8% and a present worth of NOK 1,95M to 3.07M for discount rates of 6% to 8%. With a CAPEX of 2,03M thing are beginning to look profitable. However, we do have to keep in mind that this relies on a less likely electricity price prognosis, while the other five prognoses return much worse margins at these discount rates.

At a lower prognosis, the discounted payback is at 20 years, which is very high. With a high payback, markets may shift during the project lifetime which can make the investment go from a profitable outlook to a loss. This can also make prediction of the profitability of the different configurations in DES beyond 2030 too speculative, as the project lifetime stretches even further into the future than 2024. In addition, the predictions at the last years of both Statnett and NVE's prognosis are more uncertain compared to the first years of the prognoses.

6.2 Sensitivity

Even with a risk-free discount rate at the prognosis of NVE High, the BESS prices must be reduced at almost 20% to break even. This means the prices must be reduced additional to get a margin that can be accepted. The sensitivities for BESS do not indicate that the BESS prices are sensitive in general to the different Statnett prognoses, but it seems like the BESS prices are just bad overall. With this, the results indicate that investing in BESS alone may not be economical feasible given these prognoses. While for the NVE prognoses the BESS prices seem to be somewhat sensitive. This may come of the fact that price prognoses by NVE have a boarder spread of prices compared to the price prognoses done by Statnett. This seems to make it easier for BESS to provide a cost savings.

As the discount rate rises, the PV Buy option has to drop more in price compared to PV Leasing. This may come of the fact that buying solar PVs mean one have to pay for the investment up front in comparison with leasing solar PVs. Therefore, a higher discount rate increases the cost of the investment over its lifetime, and consequently reduces the cost savings that will cover the initial cost of solar PVs. This can also be seen at the discounted payback as it rises for solar PVs when the sensitivity changes below 1 and the discount rate increases within equal prognosis. This can indicate that buying solar PVs instead of leasing them is much riskier. All though a risk premium usually must be paid when leasing, the results imply such a risk premium does not surpass the cost associated with the risk of buying solar PVs.

In both the case of PV Buy and PV Leasing, a price reduction of 5% to 15% is needed to break even at a discount rate of 6% and 8% for the NVE Basis and High. It is not inconceivable that negotiations with a supplier based on, among other things economies of scale, can help reduce prices enough to reach break even or even make the investment profitable. But even if the costs can be reduced enough, the profitability is still dependent on the correct prognoses to make a profit.

6.3 DES sizing, peak shaving, and time shifting

The claim by Gawusu et al. (2022) that distributed generation such as wind or solar power is the best way to peak shave for clients who pays demand charges does not appear to be true in our case, as the solar PVs effect on reducing the demand charges is almost zero, while instead the batteries provide a significant reduction to the demand charges as long as the demand rates are high during winter. The claim that PVs combined with BESS is becoming an even better solution for peak shaving is does not appear to be true in our case either, all though it is difficult to draw conclusions from our numbers. One of the main reasons why neither PVs nor BESS has a profitable impact on the demand charges, at least not during summer, is probably due to HOI already managing the demand load closely. This leaves few and low demand spikes to shave, and with a lower potential gain it is harder to justify the costs of the DES solutions.

The BESS has some impact on the energy charges, all though not enough for it to be profitable. This indicates that there is a time shifting effect happening, but that difference in energy rates are not great enough between the cheaper and more expensive periods to make up for the cost of BESS. The solar PVs have a great effect on reducing the energy charges. The effect is not surprisingly greatest in summer when the days are long, and sun is high up on the sky. The reason why the solar PVs are so good at reducing the energy charges, while the batteries are not can be explained by looking at the daily energy consumption pattern of the production line, combined with looking at the daily PV electricity generation pattern. We see that these patterns match up because the production lines are active during daytime and evenings, which is the same time the solar PVs are generating electricity. The solar PVs produce far less power than the production lines need so all power can be immediately spent, replacing grid purchased power. This pattern also coincides with the periods where the cost of purchasing power of the grid is usually highest. The PVs can therefore replace the most expensive power purchases in real time, leaving little need for time shifting capabilities such as BESS.

The demand charge makes up a significantly smaller part of the electricity bill of HOI then the energy charge (see Appendix A chapter A.11.2 for tables showing the charges). Typically, roughly 20% in the winter months and about 7% in the summer months. What we see when we look at the total energy cost savings compared to the CAPEX of the DES alternatives is that BESS and PVs complement each other in our case. In wintertime, when PV generation is low, but the demand rate is high the BESS provides a considerable and profitable reduction to the overall energy cost, while in summertime when solar PV conditions are good, but demand rate is low the solar panels provide an almost equally considerable and profitable reduction to the overall energy cost. Although this combination in most cases does not beat the profitability of the PV configurations without BESS, it does demonstrate how these DES capabilities complement each other. A lower BESS price, more power consumption at nighttime, higher demand rate during summer, or greater short-term price variations than we have simulated could be a more profitable and stable way of reducing energy costs using DES, not only by peak shaving the demand charge, as Gawusu et al. (2022) points to, but also by reducing the energy charge. As previously mentioned Statnett (2023b) predicts greater short-term price variations than NVE (2023) which these findings were based on. This could be an indication that the combined PV and BESS configurations are even more profitable, compared to the configurations with just PVs, than our Statnett-based simulations indicate. However, the annual average hourly energy prices in the Statnett High prognosis are 35-40% lower the NVE High prognosis, and these average prices are accurately represented in the datasets used for our simulations. For our findings to give the opposite conclusion regarding what is most profitable of just PVs or PVs and BESS combined, in the Statnett-based scenarios, the missing effect of volatility would have to constitute a greater benefit to the profitability calculation, than the lower average price constitutes a drawback to the same calculation. At a discount rate of 3.566% this constitutes a difference in present worth between the combined PV and BESS solution of the Statnett High and NVE high simulations of NOK 2,33M (See Appendix A for detailed numbers). For comparison the entire energy cost in the Statnett case is NOK 2,28M To generate these sums by additional peak shaving and time shifting based on daily volatility being up to three times higher seems highly unlikely. Therefore, we argue that our findings, based on the N-H-24-1 scenario indicating that PVs alone are more profitable combined PV and BESS (given a higher discount rate than 3,566%), are valid.

6.4 Leasing vs. buying solar PVs

In the 2024 scenarios, the results show that PV Buy on some occasions is more profitable than PV Leasing and vice versa. This shift seems to happen between 6% and 8%. Since the PV effect size is equal for PV Buy and PV Leasing, they have the same cash flow for the energy cost when compared with equal discount rate and prognosis. While the cash flow for cost of PV Buy and PV Leasing is different. The annuity for PV Leasing is bigger than PV Buy, making PV Leasing change more in profitability by variations in the discount rate. With a high enough discount rate, PV Leasing becomes more profitable than PV Buy. This can be an indication that PV Leasing is a preferred choice over PV Buy, as PV Buy is not profitable after a discount rate of 10%, while PV Leasing have a positive present worth at every scenario with NVE High. Given the NVE High prognosis and typically used discount rate for solar PV systems, PV Buy can be assessed to be a riskier investment compared to PV Leasing. In addition, with PV Leasing one can start getting a profit from day one as there is no upfront capital needed, while with PV Buy one must wait to after the discounted payback to start getting a profit on the investment. However, with a risk-free discount rate at Statnett High and NVE Basis, PV Leasing has a negative present worth, while PV Buy is positive. According to the sensitivity results, PV Leasing prices must decrease by 20% to break even at NVE Basis. All though PV Buy appears more profitably at such scenarios, a discount rate of 3,566% does not reflect the project-specific risk.

6.5 Discussion summary

We will now summarize our analysis and discussion in relation to each of our research questions. We will first answer the three supporting research questions before answering our main research question for this thesis.

RQ1-1: What is the profitability of the different possible DES configurations?

Overall, the results primarily showed poor or no profitability except in the most expensive future energy price scenarios, given that the investments happen in 2024. Most profitable configurations were characterized by very low discount rates and/or long payback periods representing a significant amount of risk in the investments. Leasing PVs appear as the best option as this performs the best given higher and arguably more relevant discount rates. The leasing option however, also relies on the most expensive energy price prognosis becoming true. The 2030 results indicate that it could be profitable to wait and instead invest in DES later. The expected reduction in DES component costs makes the configurations perform better under less expensive price prognoses.

RQ1-2: How is an overall cost reduction achieved by the DES solution?

The cost reduction is achieved by targeting two major parts of the electricity bill, the demand charge and the energy charge. Demand charge reduction is achieved by BESS enabling peak shaving strategies. These however only return positive results compared to the cost of BESS during the winter months when the demand rate is more than three times higher than in summer. The demand rate simply appears to be too low in summertime to enable profitable BESS operations with the consumption pattern of HOI and the expected future energy prices.

The energy charge reduction is primarily achieved by the solar PVs replacing grid electricity in real time, without intermediary storage. Basically, no time shifting is observed in the simulation, probably as a consequence of the consumption pattern, PV electricity generation pattern, and daily grid electricity price variation correlating, rendering BESS irrelevant.

RQ1-3: If a DES configuration is not profitable, what must change for it to become profitable?

For the unprofitable configuration to become profitable one or more of the following factors must change. Higher future energy prices could give a positive present worth for more configurations. A higher demand rate during summer could greatly affect the profitability of BESS. Greater short-term electricity price variations could improve profitability of BESS configurations. A different factory energy consumption patten could enable more time shifting which could improve profitability. A reduction in DES component costs will affect profitability a lot.

RQ1: "How can a production facility use Distributed Energy Systems based on renewable energy sources to reduce overall energy costs?".

Overall, it appears that DES solutions like PVs and BESS likely will not help reduce the overall energy costs of production facilities such as the factory of HOI. This is due to a combination of multiple factors, the most significant of which are the expected future electricity prices likely being too low, the cost of DES components still being too high, and the energy consumption pattern of the HOI production line.

6.6 Generalizations

In this sub-chapter we will first discuss the generalization and validity of our results for other commercial actors in Norway looking into the same questions regarding DES. We will then briefly discuss the potential for generalizing our results from a theoretical standpoint in regard to the existing literature on DES.

NO2 being the most expensive energy bidding zone in Norway, and the factory of HOI is situated in one of the most sunny and southern parts of the country as previously mentioned. These factors are central to the profitability calculations and are unlikely to be significantly better anywhere else in the country, but instead probably worse in terms of making DES profitable. However, different electricity distributors charge different rates. Significantly different rates, especially demand rates, would render our conclusions invalid for actors operating under such a tariff. The consumption pattern of the factory does also appear to be a significant reason why the outcome of our analysis is what it is. Significantly different consumption patterns, for instance nighttime production, will produce different results, and likely affect the profitability conclusions for various DES configurations.

Gawusu et al. (2022) claims that BESS can replace traditional methods of peak shaving. We see in our analysis that BESS can indeed achieve a peak shaving effect however in our case it is not profitable due to the reasons previously mentioned. Krishan and Suhag (2019) claim that energy storage systems can enable time shifting. This is not observed in our analysis likely due to the reasons previously explained. Based on this we must conclude that our findings are not sufficient for theoretical generalizations as there are too many case-specific factors that likely affect the outcome.

7 Conclusion

This master’s thesis has investigated the profitability potential of various DES investments for a manufacturing facility on southern Norway. The research was conducted as a case study. The results indicate that investing in DES is likely not profitable for the facility we used as our case object, mainly due to energy consumption pattern, high DES component costs, low demand rates during summer, and not sufficiently high enough energy prices expected through the project lifetime. The profitability does however appear to improve if the investment is postponed to 2030 but is still dependent on the higher electricity price prognoses becoming a reality, which appear less likely than the alternatives. Overall, leasing of solar PVs is assessed to be the preferred option as it provides a better present worth at higher discount rates and is considered to have less risk associated with it.

Our analysis imply that BESS can indeed replace traditional distributed generation-based methods of peak shaving, but not in a profitable way in our case. We do not observe time shifting effects by the BESS, likely due to the consumption pattern, daily price variation, and PV generation pattern (when PVs are included in the configuration) correlating in a way that renders intermediary storage of power unnecessary. The conclusions appear valid and relevant for other actors with similar consumption patterns, and similar grid tariffs. The overall conclusion that investing in DES likely will not be profitable appears to be transferable to other bidding zones in Norway as the conditions for profitable PV and BESS installations are likely worse, as long as the grid tariffs are similar.

The research was limited by time and processing power and as such the scope had to be narrowed down and prioritized. As part of our scope delineation process, we identified an unexplored potential in thermal storage solutions that appears interesting for future research.

In summary, given our case it does not appear to be profitable to invest in solar PVs and or BESS solutions now unless the buyer can negotiate significantly lower prices than what the current literature states as the current cost level. While energy prices currently are very high compared to the historical average, most prognoses forecast prices that are over all too low through the project lifetime for the potential DES investments to be profitable.

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Appendix A Simulation results

Table A 1: Analysis scenario coding scheme.

Source	Prognosis	Year	Sensitivity	Discount rate (Nominal)	Configuration[9]
S = Statnett N = NVE	L = Low B = Basis H = High	24 = 2024 30 = 2030	1 = All sensitivities set to 1 S = Sensitivity DES component cost analysis	3 = 3,566% 6 = 6% 8 = 8% 10 = 10% 12 = 12%	A = Base Case B = BESS (Capital cost sensitivity) C = PV Buy D = PV Buy + BESS E = PV Leasing F = BESS (Capital cost & Replacement cost sensitivity)

Table A 2: Analysis scenario overview.

Scenario	Scenario code	Prognosis	Sensitivity	Project start
Scenario 1	S-L-24-1	Statnett LOW	N/A	2024
Scenario 2	S-L-24-S	Statnett LOW	Sensitivity	2024
Scenario 3	S-B-24-1	Statnett BASIS	N/A	2024
Scenario 4	S-B-24-S	Statnett BASIS	Sensitivity	2024
Scenario 5	S-H-24-1	Statnett HIGH	N/A	2024
Scenario 6	S-H-24-S	Statnett HIGH	Sensitivity	2024
Scenario 7	N-L-24-1	NVE LOW	N/A	2024
Scenario 8	N-L-24-S	NVE LOW	Sensitivity	2024
Scenario 9	N-B-24-1	NVE BASIS	N/A	2024
Scenario 10	N-B-24-S	NVE BASIS	Sensitivity	2024
Scenario 11	N-H-24-1	NVE HIGH	N/A	2024
Scenario 12	N-H-24-S	NVE HIGH	Sensitivity	2024
Scenario 13	S-L-30-1	Statnett LOW	N/A	2030
Scenario 14	S-B-30-1	Statnett BASIS	N/A	2030
Scenario 15	S-H-30-1	Statnett HIGH	N/A	2030
Scenario 16	N-L-30-1	NVE LOW	N/A	2030
Scenario 17	N-B-30-1	NVE BASIS	N/A	2030
Scenario 18	N-H-30-1	NVE HIGH	N/A	2030

[9] In configuration B, sensitivity values are only applied to BESS Capital cost, while in configuration F sensitivity values are applied to both BESS capital cost and BESS replacement cost at the same time.

A.1 Scenario 1 - S-L-24-1

Prognosis: Statnett LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 3: Scenario 1 (S-L-24-1) Simulation configurations overview.

S-L-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A
3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Table A 4: Scenario 1 (S-L-24-1) Economic metrics.

S-L-24-1	NPC (M NOK)	LCOE (NOK/kWh)
3-A	34,86	0,370
3-B	35,22	0,374
3-C	36,38	0,386
3-D	36,70	0,389
6-A	27,84	0,388
6-B	28,19	0,393
6-C	29,72	0,413
6-D	30,03	0,418
8-A	23,66	0,402

8-B	24,00	0,408
8-C	25,75	0,437
8-D	26,06	0,443
10-A	20,47	0,416
10-B	20,79	0,423
10-C	22,72	0,462
10-D	23,02	0,468
12-A	17,97	0,430
12-B	18,29	0,438
12-C	20,35	0,486
12-D	20,65	0,494
3-E	37,84	0,401
6-E	30,09	0,419
8-E	25,49	0,433
10-E	21,97	0,447
12-E	19,24	0,460

Table A 5: Scenario 1 (S-L-24-1) Costs and present worth.

S-L-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth
3-A	1,65	0	245 371	1,40	4 460 213	0	0
3-B	1,65	0,324	236 612	1,40	4 464 129	0	-362 120
3-C	1,56	3,354	243 590	1,30	4 137 028	4691	-1 520 690
3-D	1,56	3,678	233 175	1,30	4 138 731	2255	-1 839 420
6-A	1,73	0,000	257 251	1,47	4 460 213	0	0
6-B	1,73	0,324	248 072	1,47	4 464 129	0	-345 570
6-C	1,64	3,354	255 371	1,37	4 137 028	4691	-1 876 380
6-D	1,64	3,678	244 451	1,36	4 138 731	2255	-2 187 070
8-A	1,79	0,000	266 867	1,53	4 460 213	0	0
8-B	1,80	0,324	257 351	1,53	4 464 129	0	-335 720
8-C	1,70	3,354	264 908	1,42	4 137 028	4691	-2 089 550
8-D	1,70	3,678	253 578	1,42	4 138 731	2255	-2 395 470
10-A	1,86	0,000	276 172	1,58	4 460 213	0	0
10-B	1,86	0,324	266 334	1,58	4 464 129	0	-328 380
10-C	1,76	3,354	274 137	1,47	4 137 028	4691	-2 253 700
10-D	1,76	3,678	262 413	1,46	4 138 731	2255	-2 556 180
12-A	1,92	0,000	285 047	1,63	4 460 213	0	0
12-B	1,92	0,324	274 903	1,63	4 464 129	0	-322 950
12-C	1,81	3,354	282 940	1,51	4 137 028	4691	-2 382 580
12-D	1,81	3,678	270 838	1,51	4 138 731	2255	-2 682 670
3-E	1,79	0	243 590	1,30	4 137 028	4691	-2 982 940
6-E	1,87	0	255 371	1,37	4 137 028	4691	-2 247 250
8-E	1,93	0	264 908	1,42	4 137 028	4691	-1 822 590
10-E	1,99	0	274 137	1,47	4 137 028	4691	-1 506 700
12-E	2,05	0	282 940	1,51	4 137 028	4691	-1 267 330

A.2 Scenario 2 - S-L-24-S

Prognosis: Statnett LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

BESS does not become profitable even at sensitivities = 0.05 and is therefore not included in the results.

Table A 6: Scenario 2 (S-L-24-S) Simulation configurations overview.

S-L-24-S	Discount rates	Sensitivity
3-E	3,566 %	0,4
6-E	6 %	0,4
8-E	8 %	0,4
10-E	10 %	0,45
12-E	12 %	0,45
3-C	3,566 %	0,5
6-C	6 %	0,4
8-C	8 %	0,35
10-C	10 %	0,3
12-C	12 %	0,25

Table A 7: Scenario 2 (S-L-24-S) Economic metrics.

S-L-24-S	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-E	34,74	0,368				
6-E	27,69	0,385				
8-E	23,50	0,399				
10-E	20,44	0,415				
12-E	17,92	0,428				
3-C	34,71	0,368	1	2,3	17,34	21,02
6-C	27,71	0,385	2,3	4,9	12,47	19,3
8-C	23,57	0,400	3,2	6,7	10,57	19,24
10-C	20,37	0,414	4,3	9	8,59	16,92
12-C	17,84	0,426	6	12,2	6,48	12,9

Table A 8: Scenario 2 (S-L-24-S) Costs and present worth.

S-L-24-S	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-E	1,64	0,000	243 590	1,30	4 137 028	4 691	118 993
6-E	1,72	0,000	255 371	1,37	4 137 028	4 691	149 242
8-E	1,78	0,000	264 908	1,42	4 137 028	4 691	161 961
10-E	1,85	0,000	274 137	1,47	4 137 028	4 691	28 462
12-E	1,91	0,000	282 940	1,51	4 137 028	4 691	50 120
3-C	1,56	1,677	243 590	1,30	4 137 028	4 691	156 126
6-C	1,64	1,341	255 371	1,37	4 137 028	4 691	135 790
8-C	1,70	1,174	264 908	1,42	4 137 028	4 691	90 312
10-C	1,76	1,006	274 137	1,47	4 137 028	4 691	93 839
12-C	1,81	0,838	282 940	1,51	4 137 028	4 691	132 642

A.3 Scenario 3 - S-B-24-1

Prognosis: Statnett BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 9: Scenario 3 (S-B-24-1) Simulation configurations overview.

S-B-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Since the base case configuration is the winning system in every simulation in scenario 1, ROI, IRR, simple payback and discounted payback are not provided.

Table A 10: Scenario 3 (S-B-24-1) Economic metrics.

S-B-24-1	NPC (M NOK)	LCOE (NOK/kWh)
3-A	46,9	0,497
3-B	47,2	0,501
3-C	47,7	0,505
3-D	47,9	0,508
6-A	37,2	0,518
6-B	37,5	0,522
6-C	38,5	0,535
6-D	38,7	0,539
8-A	31,4	0,534
8-B	31,7	0,539
8-C	33	0,561
8-D	33,3	0,566
10-A	27,1	0,551
10-B	27,4	0,557
10-C	28,9	0,587
10-D	29,2	0,593
12-A	23,7	0,567
12-B	24	0,574
12-C	25,7	0,614
12-D	26	0,621
3-E	49,12	0,521
6-E	38,83	0,540
8-E	32,76	0,556
10-E	28,16	0,572
12-E	24,59	0,588

Table A 11: Scenario 3 (S-B-24-1) Costs and present worth.

S-B-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth
3-A	2,22	0	329 969	1,89	4 460 212	0	0
3-B	2,22	0,32	318 192	1,89	4 464 763	0	-334 240
3-C	2,1	3,35	327 584	1,75	4 137 028	4691	-766 110

3-D	2,09	3,67	313 578	1,75	4 139 382	2255	-1 042 570
6-A	2,31	0	343 341	1,97	4 460 212	0	0
6-B	2,31	0,32	331 091	1,96	4 464 763	0	-324 100
6-C	2,18	3,35	340 844	1,82	4 137 028	4691	-1 291 350
6-D	2,18	3,67	326 268	1,82	4 139 382	2255	-1 569 400
8-A	2,38	0	354 343	2,03	4 460 212	0	0
8-B	2,38	0,32	341 707	2,03	4 464 763	0	-316 870
8-C	2,25	3,35	351 753	1,88	4 137 028	4691	-1 602 420
8-D	2,24	3,67	336 709	1,88	4 139 382	2255	-1 880 170
10-A	2,46	0	365 138	2,09	4 460 212	0	0
10-B	2,45	0,32	352 128	2,09	4 464 763	0	-310 960
10-C	2,32	3,35	362 459	1,94	4 137 028	4691	-1 839 590
10-D	2,31	3,67	346 956	1,94	4 139 382	2255	-2 116 700
12-A	2,53	0	375 567	2,15	4 460 212	0	0
12-B	2,52	0,32	362 199	2,15	4 464 763	0	-306 360
12-C	2,38	3,35	372 802	2	4 137 028	4691	-2 024 060
12-D	2,38	3,67	356 856	1,99	4 139 382	2255	-2 300 630
3-E	2,32	0	327 584	1,75	4 137 028	4691	-2 228 360
6-E	2,41	0	340 844	1,82	4 137 028	4691	-1 662 210
8-E	2,48	0	351 753	1,88	4 137 028	4691	-1 335 460
10-E	2,56	0	362 459	1,94	4 137 028	4691	-1 092 600
12-E	2,62	0	372 802	2,00	4 137 028	4691	-908 820

A.4 Scenario 4 – S-B-24-S

Prognosis: Statnett BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 12: Scenario 4 (S-B-24-S) Simulation configurations overview.

S-B-24-S	Discount rates	Sensitivity
3-E	3,566 %	0,55
6-E	6 %	0,55
8-E	8 %	0,55
10-E	10 %	0,60
12-E	12 %	0,60
3-C	3,566 %	0,75
6-C	6 %	0,6
8-C	8 %	0,5
10-C	10 %	0,45
12-C	12 %	0,35

3-B	3,566 %	0,05
6-B	6 %	0,05
8-B	8 %	0,05
10-B	10 %	0,05
12-B	12 %	0,05
3-F	3,566 %	0,1
6-F	6 %	0,1
8-F	8 %	0,1
10-F	10 %	0,1
12-F	12 %	0,1

Table A 13: Scenario 4 (S-B-24-S) Economic metrics.

S-B-24-S	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-E	46,8	0,496				
6-E	37	0,515				
8-E	31,3	0,531				
10-E	26,9	0,547				
12-E	23,5	0,562				
3-C	46,8	0,496	0,7	1,6	19,73	23,82
6-C	37,1	0,516	1,9	4	14,4	23,55
8-C	31,4	0,532	3,1	6,2	11,44	21,82
10-C	27,1	0,55	3,9	7,7	10,03	24,55
12-C	23,5	0,562	6,2	11,7	6,93	14,56
3-B	46,9	0,497	1,4	65,7	1,33	1,35
6-B	37,2	0,517	1,4	65,7	1,33	1,39
8-B	31,4	0,534	1,4	65,7	1,33	1,43
10-B	27	0,55	1,4	65,7	1,33	1,47
12-B	23,7	0,566	1,4	65,7	1,33	1,51
3-F	46,87	0,497	2,9	17,4	3,44	3,58
6-F	37,15	0,517	2,9	17,4	3,44	3,85
8-F	31,41	0,534	2,9	17,4	3,44	4,07
10-F	27,05	0,550	2,9	17,4	3,44	4,27
12-F	23,67	0,566	2,9	17,4	3,44	4,49

Table A 14: Scenario 4 (S-B-24-S) Costs and present worth.

S-B-24-S	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-E	2,21	0	327 584	1,75	4 137 028	4691	98 080
6-E	2,3	0	340 844	1,82	4 137 028	4691	135 153

8-E	2,37	0	351 753	1,88	4 137 028	4691	152 947
10-E	2,44	0	362 459	1,94	4 137 028	4691	163 448
12-E	2,51	0	372 802	2	4 137 028	4691	169 100
3-C	2,1	2,51	327 584	1,75	4 137 028	4691	74 675
6-C	2,18	2,01	340 844	1,82	4 137 028	4691	52 006
8-C	2,25	1,68	351 753	1,88	4 137 028	4691	75 981
10-C	2,32	1,51	362 459	1,94	4 137 028	4691	6 334
12-C	2,38	1,17	372 802	2	4 137 028	4691	156 909
3-B	2,22	0,016	318 192	1,89	4 464 763	0	7 739
6-B	2,31	0,016	331 091	1,96	4 464 763	0	11 088
8-B	2,38	0,016	341 707	2,03	4 464 763	0	13 132
10-B	2,45	0,016	352 128	2,09	4 464 763	0	14 556
12-B	2,52	0,016	362 199	2,15	4 464 763	0	15 439
3-F	2,22	0,0324	318 192	1,89	4 466 842	0	20 450
6-F	2,31	0,0324	331 091	1,96	4 466 842	0	15 607
8-F	2,38	0,0324	341 707	2,03	4 466 842	0	12 349
10-F	2,45	0,0324	352 128	2,09	4 466 842	0	9 549
12-F	2,52	0,0324	362 199	2,15	4 466 842	0	7 096

A.5 Scenario 5 – S-H-24-1

Prognosis: Statnett HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 15: Scenario 5 (S-H-24-1) Simulation configurations overview.

S-H-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A

12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A
3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Table A 16: Scenario 5 (S-H-24-1) Economic metrics.

S-H-24-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	61,2	0,649				
3-B	61,4	0,652				
3-C	61,1	0,647	0,8	1,7	19,45	23,41
3-D	61,2	0,649				
6-A	48,7	0,678				
6-B	48,9	0,682				
6-C	49,3	0,686				
6-D	49,4	0,688				
8-A	41,3	0,703				
8-B	41,6	0,707				
8-C	42,3	0,718				
8-D	42,5	0,722				
10-A	35,7	0,726				
10-B	35,9	0,731				
10-C	37	0,752				
10-D	37,2	0,756				
12-A	31,3	0,749				
12-B	31,6	0,755				
12-C	32,9	0,785				
12-D	33,1	0,791				
3-E	63,6	0,675				
6-E	50,8	0,707				
8-E	43,2	0,734				
10-E	37,3	0,759				
12-E	32,8	0,784				

Table A 17: Scenario 5 (S-H-24-1) Costs and present worth.

S-H-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	2,9	0	430 671	2,47	4 460 212		0
3-B	2,86	0,32	415 230	2,46	4 465 119		-260 040
3-C	2,73	3,35	427 544	2,29	4 137 028	4 691	131 720

3-D	2,72	3,67	5	2,28	4 139 760	2 255	-52 590
6-A	3,03	0	449 998	2,58	4 460 212		0
6-B	3,02	0,32	433 891	2,57	4 465 119		-263 830
6-C	2,85	3,35	446 656	2,39	4 137 028	4 691	-566 790
6-D	2,84	3,67	427 546	2,39	4 139 760	2 255	-769 890
8-A	3,13	0	465 943	2,67	4 460 212		0
8-B	3,13	0,32	449 289	2,67	4 465 119		-265 040
8-C	2,95	3,35	462 478	2,47	4 137 028	4 691	-981 130
8-D	2,94	3,67	442 688	2,47	4 139 760	2 255	-1 194 380
10-A	3,24	0	481 611	2,76	4 460 212		0
10-B	3,23	0,32	464 422	2,76	4 465 119		-265 660
10-C	3,05	3,35	478 024	2,56	4 137 028	4 691	-1 297 580
10-D	3,04	3,67	457 566	2,56	4 139 760	2 255	-1 518 260
12-A	3,34	0	496 753	2,85	4 460 212		0
12-B	3,33	0,32	479 050	2,84	4 465 119		-266 190
12-C	3,15	3,35	493 048	2,64	4 137 028	4 691	-1 544 200
12-D	3,14	3,67	471 945	2,64	4 139 760	2 255	-1 770 700
3-E	3,01	0	447 820	2,56	4 460 212		-1 330 540
6-E	3,15	0	469 170	2,69	4 460 212		-937 650
8-E	3,27	0	486 632	2,79	4 460 212		-714 170
10-E	3,39	0	503 646	2,88	4 460 212		-550 590
12-E	3,5	0	519 938	2,98	4 460 212		-428 950

A.6 Scenario 6 – S-H-24-S

Prognosis: Statnett HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 18: Scenario 6 (S-H-24-S) Simulation configurations overview.

S-H-24-S	Discount rates	Sensitivity
3-E	3,566 %	0,7
6-E	6 %	0,75
8-E	8 %	0,75
10-E	10 %	0,8
12-E	12 %	0,8

3-C	3,566 %	1
6-C	6 %	0,8
8-C	8 %	0,7
10-C	10 %	0,6
12-C	12 %	0,5
3-B	3,566 %	0,3
6-B	6 %	0,25
8-B	8 %	0,25
10-B	10 %	0,2
12-B	12 %	0,2

Table A 19: Scenario 6 (S-H-24-S) Economic metrics.

S-H-24-S	**NPC (M NOK)**	**LCOE (NOK/kWh)**	**ROI (%)**	**IRR (%)**	**Simple payback (years)**	**Discounted payback (years)**
3-E	61	0,646				
6-E	48,7	0,677				
8-E	41,2	0,7				
10-E	35,7	0,725				
12-E	31,3	0,747				
3-C	61,1	0,647	0,8	1,7	19,45	23,41
6-C	48,6	0,676	5,6	10,9	7,25	12,82
8-C	41,3	0,701	2,8	5,8	11,8	24,08
10-C	35,7	0,725	4	8	9,57	22,69
12-C	31,2	0,745	5,6	10,9	7,25	17,14
3-B	61,2	0,649	0,5	2,1	5,93	6,77
6-B	48,7	0,678	2,7	15	3,75	4,61
8-B	41,3	0,703	1,3	6,8	4,73	5,39
10-B	35,7	0,726	2,7	15	3,75	4,61
12-B	31,3	0,749	2,7	15	3,75	4,88

Table A 20: Scenario 6 (S-H-24-S) Costs and present worth.

S-H-24-S	**O&M (M NOK)**	**CAPEX (M NOK)**	**Demand cost (NOK)**	**Energy cost (M NOK)**	**Energy purchased (kWh)**	**Energy sold (kWh)**	**Present worth (NOK)**
3-E	2,89	0	427 544	2,29	4 137 028	4691	220 429
6-E	3,02	0	446 707	2,39	4 137 028	4691	60 885
8-E	3,13	0	462 517	2,47	4 137 028	4691	112 726
10-E	3,24	0	478 054	2,56	4 137 028	4691	7 660
12-E	3,34	0	493 071	2,64	4 137 028	4691	50 123

3-C	2,73	3,35	427 544	2,29	4 137 028	4691	134 895
6-C	2,85	2,68	446 707	2,39	4 137 028	4691	380 827
8-C	2,95	2,35	462 517	2,47	4 137 028	4691	27 185
10-C	3,05	2,01	478 054	2,56	4 137 028	4691	45 782
12-C	3,15	1,68	493 071	2,64	4 137 028	4691	134 207
3-B	2,89	0,097	415 298	2,46	4 465 120	0	2 656
6-B	3,02	0,081	433 941	2,57	4 465 120	0	12 210
8-B	3,13	0,081	449 327	2,67	4 465 120	0	1 257
10-B	3,23	0,065	464 451	2,76	4 465 120	0	12 210
12-B	3,33	0,065	479 072	2,84	4 465 120	0	7 833

A.7 Scenario 7 - N-L-24-1

Prognosis: NVE LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 21: Scenario 7 (N-L-24-1) Simulation configurations overview.

N-L-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A
3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Table A 22: Scenario 7 (N-L-24-1) Economic metrics.

N-L-24-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	4,38	0,465				
3-B	4,41	0,468				
3-C	4,48	0,475				
3-D	4,50	0,478				
6-A	3,58	0,499				
6-B	3,61	0,503				
6-C	3,72	0,517				
6-D	3,74	0,521				
8-A	3,10	0,527				
8-B	3,13	0,532				
8-C	3,26	0,554				
8-D	3,29	0,558				
10-A	2,72	0,554				
10-B	2,75	0,560				
10-C	2,91	0,591				
10-D	2,93	0,596				
12-A	2,43	0,580				
12-B	2,45	0,587				
12-C	2,62	0,627				
12-D	2,65	0,634				
3-E	46,24	0,490				
6-E	37,56	0,523				
8-E	32,34	0,549				
10-E	28,31	0,575				
12-E	25,13	0,601				

Table A 23: Scenario 7 (N-L-24-1) Costs and present worth.

N-L-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	2,07	0,000	308 281	1,77	4 460 213		0
3-B	2,07	0,324	297 289	1,76	4 464 453		-354 300
3-C	1,96	3,354	306 039	1,64	4 137 028	4691	-958 210
3-D	1,96	3,678	292 952	1,64	4 139 070	2255	-1 257 470
6-A	2,22	0,000	330 719	1,89	4 460 213		0
6-B	2,22	0,324	318 936	1,89	4 464 453		-333 710
6-C	2,10	3,354	328 301	1,76	4 137 028	4691	-1 375 900
6-D	2,10	3,678	314 261	1,75	4 139 070	2255	-1 664 530
8-A	2,35	0,000	349 172	2,00	4 460 213		0
8-B	2,35	0,324	336 743	2,00	4 464 453		-320 890
8-C	2,22	3,354	346 610	1,86	4 137 028	4691	-1 630 120

8-D	2,21	3,678	331 787	1,85	4 139 070	2255	-1 911 910
10-A	2,47	0,000	367 229	2,10	4 460 213		0
10-B	2,47	0,324	354 171	2,10	4 464 453		-311 190
10-C	2,33	3,354	364 528	1,95	4 137 028	4691	-1 828 900
10-D	2,33	3,678	348 938	1,95	4 139 070	2255	-2 105 590
12-A	2,59	0,000	384 590	2,20	4 460 213		0
12-B	2,58	0,324	370 931	2,20	4 464 453		-303 990
12-C	2,44	3,354	381 755	2,04	4 137 028	4691	-1 987 490
12-D	2,44	3,678	365 430	2,04	4 139 070	2255	-2 260 620
3-E	2,19	0	306 039	1,64	4 137 028		-2 420 470
6-E	2,33	0	328 301	1,76	4 137 028		-1 746 770
8-E	2,45	0	346 610	1,86	4 137 028		-1 363 160
10-E	2,57	0	364 528	1,95	4 137 028		-1 081 910
12-E	2,68	0	381 755	2,04	4 137 028		-872 250

A.8 Scenario 8 - N-L-24-S

Prognosis: NVE LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 24: Scenario 8 (N-L-24-S) Simulation configurations overview.

N-L-24-S	Discount rates	Sensitivity
3-E	3,566 %	0,5
6-E	6 %	0,55
8-E	8 %	0,55
10-E	10 %	0,60
12-E	12 %	0,60
3-C	3,566 %	0,7
6-C	6 %	0,55
8-C	8 %	0,5
10-C	10 %	0,45
12-C	12 %	0,4
3-B	3,566 %	0,02
6-B	6 %	0,05
8-B	8 %	0,05
10-B	10 %	0,05
12-B	12 %	0,1

Table A 25: Scenario 8 (N-L-24-S) Economic Metrics.

N-L-24-S	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-E	43,66	0,463				
6-E	35,76	0,498				
8-E	30,85	0,524				
10-E	27,19	0,553				
12-E	24,17	0,578				
3-C	4,38	0,464	12,1	29,3	2,76	2,98
6-C	3,57	0,496	1,9	4,7	11,83	20,04
8-C	3,09	0,525	2,4	6,1	9,90	22,18
10-C	2,72	0,553	3,2	7,8	8,26	23,46
12-C	2,42	0,579	4,1	9,9	6,82	21,54
3-B	43,82	0,46	-4,2	N/A	0,40	0,41
6-B	35,81	0,50	-4,1	N/A	1,00	1,05
8-B	30,97	0,53	-4,1	N/A	1,00	1,08
10-B	27,21	0,55	-4,1	N/A	1,00	1,10
12-B	24,26	0,58	-4,0	N/A	2,21	2,66

Table A 26: Scenario 8 (N-L-24-S) Costs and present worth.

N-L-24-S	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-E	2,07	0	306 039	1,64	4 137 028	4691	164 477
6-E	2,22	0	328 301	1,76	4 137 028	4691	50 601
8-E	2,34	0	346 610	1,86	4 137 028	4691	125 251
10-E	2,47	0	364 528	1,95	4 137 028	4691	34 582
12-E	2,58	0	381 755	2,04	4 137 028	4691	85 894
3-C	1,96	2,348	306 039	1,64	4 137 028	4691	1 306 996
6-C	2,10	1,844	328 301	1,76	4 137 028	4691	133 228
8-C	2,22	1,677	346 610	1,86	4 137 028	4691	46 695
10-C	2,33	1,509	364 528	1,95	4 137 028	4691	15 597
12-C	2,44	1,341	381 755	2,04	4 137 028	4691	24 677
3-B	2,07	0,006	297 289	1,76	4 464 453	0	2 243
6-B	2,22	0,016	318 936	1,89	4 464 453	0	4 378
8-B	2,35	0,016	336 743	2,00	4 464 453	0	11 020
10-B	2,47	0,016	354 171	2,10	4 464 453	0	15 603
12-B	2,58	0,032	370 931	2,20	4 464 453	0	2 437

A.9 Scenario 9 – N-B-24-1

Prognosis: NVE BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 27: Scenario 9 (N-B-24-1) Simulation configurations overview.

N-B-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A
3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Table A 28: Scenario 9 (N-B-24-1) Economic metrics.

N-B-24-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	67,80	0,719				
3-B	68,02	0,722				
3-C	67,25	0,713	1,5	3,3	15,31	18,07
3-D	67,39	0,715	1,3	2,9	16,19	19,22

6-A	53,83	0,750
6-B	54,07	0,753
6-C	54,08	0,752
6-D	54,25	0,755
8-A	45,53	0,774
8-B	45,77	0,778
8-C	46,25	0,785
8-D	46,44	0,789
10-A	39,19	0,797
10-B	39,43	0,802
10-C	40,27	0,818
10-D	40,46	0,823
12-A	34,24	0,819
12-B	34,49	0,825
12-C	35,60	0,851
12-D	35,81	0,856
3-E	68,71	0,728
6-E	54,45	0,758
8-E	45,98	0,781
10-E	39,52	0,803
12-E	34,49	0,824

Table A 29: Scenario 9 (N-B-24-1) Costs and present worth.

N-B-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	3,21	0,000	477 066	2,73	4 460 213	0	0
3-B	3,20	0,324	460 020	2,73	4 464 361	0	-225 660
3-C	3,02	3,354	473 607	2,53	4 137 028	4691	684 184
3-D	3,01	3,678	453 352	2,53	4 138 976	2255	592 103
6-A	3,34	0,000	497 300	2,85	4 460 213	0	0
6-B	3,34	0,324	479 533	2,84	4 464 361	0	-236 950
6-C	3,15	3,354	493 671	2,64	4 137 028	4691	-246 410
6-D	3,14	3,678	472 554	2,64	4 138 976	2255	-416 760
8-A	3,45	0,000	513 450	2,94	4 460 213	0	0
8-B	3,45	0,324	495 114	2,94	4 464 361	0	-242 880
8-C	3,25	3,354	509 687	2,73	4 137 028	4691	-717 840
8-D	3,24	3,678	487 882	2,72	4 138 976	2255	-904 160
10-A	3,56	0,000	528 824	3,03	4 460 213	0	0
10-B	3,55	0,324	509 951	3,03	4 464 361	0	-247 250
10-C	3,35	3,354	524 934	2,81	4 137 028	4691	-1 079 230
10-D	3,34	3,678	502 476	2,81	4 138 976	2255	-1 277 620
12-A	3,65	0,000	543 194	3,11	4 460 213	0	0
12-B	3,65	0,324	523 825	3,11	4 464 361	0	-250 780
12-C	3,44	3,354	539 187	2,89	4 137 028	4691	-1 361 780
12-D	3,43	3,678	516 118	2,88	4 138 976	2255	-1 569 710
3-E	3,25	0,000	473 607	2,53	4 137 028	4691	-917 450

6-E	3,38	0,000	493 671	2,64	4 137 028	4691	-617 270
8-E	3,49	0,000	509 687	2,73	4 137 028	4691	-450 880
10-E	3,59	0,000	524 934	2,81	4 137 028	4691	-332 230
12-E	3,68	0,000	539 187	2,89	4 137 028	4691	-246 540

A.10 Scenario 10 – N-B-24-S

Prognosis: NVE BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 30: Scenario 10 (N-B-24-S) Simulation configurations overview.

N-B-24-S	Discount rates	Sensitivity
3-E	3,566 %	0,8
6-E	6 %	0,85
8-E	8 %	0,85
10-E	10 %	0,9
12-E	12 %	0,9
3-C	3,566 %	1
6-C	6 %	0,95
8-C	8 %	0,8
10-C	10 %	0,7
12-C	12 %	0,6
3-B	3,566 %	0,45
6-B	6 %	0,35
8-B	8 %	0,3
10-B	10 %	0,3
12-B	12 %	0,25

Table A 31: Scenario 10 (N-B-24-S) Economic Metrics.

N-B-24-S	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-E	69,7	0,739				
6-E	55,5	0,773				
8-E	46,9	0,797				
10-E	40,5	0,823				
12-E	35,3	0,845				
3-C	69,3	0,734	1,5	3,3	15,31	18,07

6-C	55,6	0,773	1,8	3,8	14,15	24,31
8-C	47	0,799	2,9	5,9	11	23,46
10-C	40,5	0,824	3,9	7,7	9,26	24,37
12-C	35,4	0,845	5,2	10	7,72	21,37
3-B	70	0,742	0,4	1,4	8,95	9,66
6-B	55,6	0,774	1,7	5,7	6,39	7,84
8-B	47,1	0,8	2,7	9	5,4	6,88
10-B	40,5	0,825	2,7	9	5,4	7,76
12-B	35,4	0,847	4	13,8	4,56	6,26

Table A 32: Scenario 10 (N-B-24-S) Costs and present worth.

N-B-24-S	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-E	3,3	0	488 836	2,61	4 137 028	4691	252 729
6-E	3,45	0	510 139	2,73	4 137 028	4691	94 152
8-E	3,56	0	527 003	2,82	4 137 028	4691	142 056
10-E	3,68	0	542 940	2,9	4 137 028	4691	31 039
12-E	3,77	0	557 731	2,98	4 137 028	4691	66 748
3-C	3,12	3,35	488 836	2,61	4 137 028	4691	684 184
6-C	3,26	3,18	510 139	2,73	4 137 028	4691	36 594
8-C	3,36	2,68	527 003	2,82	4 137 028	4691	52 229
10-C	3,46	2,35	542 940	2,9	4 137 028	4691	13 239
12-C	3,56	2,01	557 731	2,98	4 137 028	4691	55 324
3-B	3,3	0,15	474 805	2,82	4 465 275	0	60
6-B	3,45	0,11	495 523	2,94	4 465 275	0	11 516
8-B	3,56	0,10	511 928	3,04	4 465 275	0	15 022
10-B	3,67	0,10	527 436	3,13	4 465 275	0	4 968
12-B	3,77	0,08	541 834	3,22	4 465 275	0	12 967

A.11 Scenario 11 – N-H-24-1

Prognosis: NVE HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 33: Scenario 11 (N-H-24-1) Simulation configurations overview.

N-H-24-1	Discount rates	Sensitivity
3-A	3,566 %	N/A

3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A
3-E	3,566 %	N/A
6-E	6 %	N/A
8-E	8 %	N/A
10-E	10 %	N/A
12-E	12 %	N/A

Table A 34: Scenario 11 (N-H-24-1) Economic metrics.

N-H-24-1	**NPC (M NOK)**	**LCOE (NOK/kWh)**	**ROI (%)**	**IRR (%)**	**Simple payback (years)**	**Discounted payback (years)**
3-A	94,36	1,001				
3-B	94,45	1,002				
3-C	92,11	0,976	3,8	6,8	10,5	11,64
3-D	92,08	0,976	3,6	6,5	10,54	12,34
6-A	73,89	1,029				
6-B	74,02	1,031				
6-C	72,85	1,013	3,8	6,8	10,48	14,59
6-D	72,89	1,015	3,6	6,5	10,74	15,18
8-A	61,79	1,051				
8-B	61,95	1,053				
8-C	61,47	1,044	3,8	6,8	10,48	19,48
8-D	61,55	1,046	3,6	6,5	10,74	20,48
10-A	52,60	1,070				
10-B	52,78	1,074				
10-C	52,82	1,074				
10-D	52,93	1,077				
12-A	45,47	1,088				
12-B	45,67	1,092				
12-C	46,12	1,102				
12-D	46,25	1,106				
3-E	93,61	0,992				
6-E	73,25	1,019				
8-E	61,23	1,040				

10-E	52,09	1,059
12-E	45,02	1,076

Table A 35: Scenario 11 (N-H-24-1) Costs and present worth.

N-H-24-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	4,46	0,000	664 079	3,80	4 460 213	0	0
3-B	4,45	0,324	640 322	3,80	4 464 991	0	-88 080
3-C	4,20	3,354	659 270	3,53	4 137 028	4691	2 254 110
3-D	4,18	3,678	631 070	3,52	4 139 619	2255	2 280 590
6-A	4,59	0,000	682 736	3,91	4 460 213	0	0
6-B	4,58	0,324	658 306	3,90	4 464 991	0	-131 890
6-C	4,32	3,354	677 757	3,62	4 137 028	4691	1 051 843
6-D	4,30	3,678	648 759	3,62	4 139 619	2255	1 041 729
8-A	4,69	0,000	697 023	3,99	4 460 213	0	0
8-B	4,67	0,324	672 085	3,99	4 464 991	0	-157 250
8-C	4,41	3,354	691 915	3,70	4 137 028	4691	328 622
8-D	4,39	3,678	662 307	3,70	4 139 619	2255	271 312
10-A	4,77	0,000	710 072	4,06	4 460 213	0	0
10-B	4,76	0,324	684 676	4,06	4 464 991	0	-176 420
10-C	4,49	3,354	704 846	3,77	4 137 028	4691	-221 170
10-D	4,47	3,678	674 681	3,77	4 139 619	2255	-333 410
12-A	4,85	0,000	721 723	4,13	4 460 213	0	0
12-B	4,84	0,324	695 924	4,13	4 464 991	0	-191 370
12-C	4,56	3,354	716 392	3,83	4 137 028	4691	-644 120
12-D	4,54	3,678	685 731	3,83	4 139 619	2255	-779 720
3-E	4,43	0,000	659 270	3,53	4 137 028	4691	808 277
6-E	4,55	0,000	677 757	3,62	4 137 028	4691	677 802
8-E	4,64	0,000	691 915	3,70	4 137 028	4691	592 402
10-E	4,73	0,000	704 846	3,77	4 137 028	4691	521 787
12-E	4,80	0,000	716 392	3,83	4 137 028	4691	462 737

A.11.1 Various BESS sizes

To investigate what effect the size of the BESS has on profitability we simulated scenario N-H-24-1 with BESS sizes off 100 kWh, 1000 kWh, 10 000 kWh, and 100 000 kWh at a discount rate of 3.566%. We chose this scenario as it showed the best potential for BESS profitability as it was the only scenario were HOMER Grid proposed the combined PV and BESS solution (3-D) over the buy PV only solution (3-C). The results in Table A 36 and Table A 37show that as BESS sizes increase, profitability diminishes quickly as the LCOE rises.

Table A 36: Scenario 11 (N-H-24-1) Economic metrics for various BESS sizes.

N-H-24-1 (Discount rate = 3.566%)	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (Years)	Discounted payback (Years)
3-C	92.11	0.976	3.8	6.8	10.5	11.64
3-D 100kWh	92.04	0.976	3.6	6.5	10.81	12.08
3-D 1000 kWh	95.44	1.012				
3-D 10 000 kWh	143.98	1.528				
3-D 100 000 kWh	648.85	6.884				

Table A 37: Scenario 11 (N-H-24-1) Costs and present worth for various BESS sizes.

N-H-24-1 (Discount rate = 3.566%)	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-C	4.20	3.354	659 269.60	35.26	4 137 028.00	4691	2 254 104
3-D 100kWh	4.18	3.678	631 070.30	35.22	4 140 348.00	2255	2 318 266
3-D 1000 kWh	4.20	6.596	561 386.20	35.12	4 175 790.00	0	-1 075 297
3-D 10 000 kWh	5.12	35.779	475 548.00	35.22	4 251 969.00	5	-49 622 280
3-D 100 000 kWh	15.20	327.605	627 507.00	34.75	4 291 553.00	0	-554 485 300

A.11.2 Monthly demand charges and energy charges

To investigate what effect BESS and solar PVs has on the demand and energy charges of HOI, we simulated N-H-24-1 with additional BESS and PV sizes at a discount rate of 3.566%. We then compared the demand and energy charges, as well as the total energy cost, each month of year 1 in the simulation to the average monthly CAPEX of each configuration. This allows us to see if a configuration provides a positive contribution to the different parts of the energy bill relative to the necessary investment.

Table A 38: Scenario 11 (N-H-24-1) CAPEX for various DES component sizes.

CAPEX (NOK)

Period	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
Lifetime	0	324251	1621255	3242510	4863765	6485020	8106275	9727530	1676813	3353625	6707250	13738751
Annually	0	12970	64850	129700	194551	259401	324251	389101	67073	134145	268290	549550
Monthly	0	1081	5404	10808	16213	21617	27021	32425	5589	11179	22358	45796

Period	Base case (A)	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
Lifetime	0	3677876	4974880	6596135	8217390	9838645	11459900	13081155
Annually	0	147115	198995	263845	328696	393546	458396	523246
Monthly	0	12260	16583	21987	27391	32795	38200	43604

Table A 39: Scenario 11 (N-H-24-1) Monthly demand charges in Year 1 for various DES component sizes.

Monthly demand charges (NOK)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	98 366	94 396	89 984	85 943	82 015	79 462	78 335	77 066	98 032	97 698	97 029	93 128
February	95 882	92 561	86 253	83 360	80 871	78 554	76 356	73 884	95 882	95 882	95 882	92 561
March	98 366	94 114	87 484	83 970	81 029	78 616	76 080	73 544	98 366	98 366	98 366	93 269
April	30 119	28 558	26 158	25 883	24 503	24 330	24 244	23 640	30 082	30 046	29 974	28 169
May	30 895	30 090	29 072	28 056	27 878	27 347	27 081	26 727	29 996	29 873	29 628	27 856
June	30 895	30 444	29 471	28 895	28 320	27 966	28 320	28 320	30 339	30 113	29 796	28 453
July	30 895	30 577	29 559	28 586	27 966	27 789	26 904	26 462	30 783	30 671	30 447	28 497
August	30 895	30 356	29 426	28 276	27 477	26 727	30 975	30 975	30 895	30 895	30 895	29 382
September	30 895	30 356	29 471	28 674	27 966	27 966	30 975	30 975	30 895	30 895	30 895	29 205
October	98 863	98 271	96 005	93 315	91 049	88 925	86 660	84 394	98 863	98 863	98 863	96 855
November	97 870	94 200	89 302	86 910	84 251	81 864	79 621	77 098	97 373	97 373	97 373	93 919
December	68 062	63 170	58 527	54 786	51 277	47 901	44 843	41 790	67 821	67 581	67 101	61 793

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + DESS (D) 1000 kWh	PV Buy + DESS (D) 1500 kWh	PV Buy + DESS (D) 2000 kWh	PV Buy + DESS (D) 2500 kWh	PV Buy + DESS (D) 3000 kWh
January	93 551	89 562	85 564	81 637	78 898	77 771	76 785
February	92 561	86 244	82 171	79 738	77 455	74 983	73 060
March	93 269	86 788	82 473	80 025	77 489	74 953	72 699
April	28 299	25 867	23 726	22 950	22 346	22 222	21 569
May	28 851	26 888	25 665	24 869	24 515	24 426	24 426
June	29 117	27 789	26 924	25 842	25 134	25 488	25 311
July	29 559	27 789	26 759	25 989	25 311	24 603	23 807
August	29 648	27 789	26 871	26 113	25 364	24 780	24 426
September	29 382	27 966	27 435	26 373	26 196	27 966	30 975
October	97 138	93 173	90 271	87 978	85 722	83 483	81 244
November	93 919	88 960	86 350	83 936	81 548	79 621	76 817
December	62 682	58 250	54 396	51 082	47 651	44 843	41 559

All PVs configuration D is 375 kWp

Table A 40: Scenario 11 (N-H-24-1) The change in monthly demand charges in Year 1 for various DES component sizes.

Change in demand charges from Base case (NOK)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	0	3971	8382	12424	16351	18905	20032	21300	334	669	1338	5239
February	0	3321	9630	12522	15011	17329	19526	21998	0	0	0	3321
March	0	4252	10883	14396	17337	19750	22286	24822	0	0	0	5098
April	0	1561	3960	4235	5616	5788	5875	6479	36	72	144	1949
May	0	805	1822	2839	3017	3548	3814	4168	899	1021	1266	3039
June	0	451	1424	1999	2575	2929	2575	2575	555	782	1099	2442
July	0	318	1336	2309	2929	3106	3991	4433	112	224	448	2398
August	0	539	1468	2619	3418	4168	-80	-80	0	0	0	1513
September	0	539	1424	2221	2929	2929	-80	-80	0	0	0	1690
October	0	592	2858	5548	7814	9938	12203	14469	0	0	0	2008
November	0	3670	8568	10959	13618	16006	18249	20772	497	497	497	3950
December	0	4892	9535	13276	16785	20160	23219	26271	240	480	961	6269

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	4816	8805	12803	16730	19468	20595	21582
February	3321	9638	13711	16144	18427	20899	22822
March	5098	11579	15893	18341	20877	23413	25667
April	1820	4252	6392	7169	7773	7897	8549
May	2044	4007	5230	6026	6380	6469	6469
June	1778	3106	3971	5053	5761	5407	5584
July	1336	3106	4136	4906	5584	6292	7088
August	1247	3106	4024	4782	5531	6115	6469
September	1513	2929	3460	4522	4699	2929	-80
October	1725	5690	8593	10885	13142	15381	17620
November	3950	8909	11520	13934	16321	18249	21052
December	5379	9812	13665	16980	20410	23219	26503

All PVs configuration D is 375 kWp

Table A 41: Scenario 11 (N-H-24-1) The relative improvement in monthly demand charges per CAPEX in Year 1 for various DES component sizes.

Relative improvement in demand charge per CAPEX compared to Base case (1 = Break even)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	3.67	1.55	1.15	1.01	0.87	0.74	0.66	0.06	0.06	0.06	0.11
February	1.00	3.07	1.78	1.16	0.93	0.80	0.72	0.68	0.00	0.00	0.00	0.07
March	1.00	3.93	2.01	1.33	1.07	0.91	0.82	0.77	0.00	0.00	0.00	0.11
April	1.00	1.44	0.73	0.39	0.35	0.27	0.22	0.20	0.01	0.01	0.01	0.04
May	1.00	0.74	0.34	0.26	0.19	0.16	0.14	0.13	0.16	0.09	0.06	0.07
June	1.00	0.42	0.26	0.18	0.16	0.14	0.10	0.08	0.10	0.07	0.05	0.05
July	1.00	0.29	0.25	0.21	0.18	0.14	0.15	0.14	0.02	0.02	0.02	0.05
August	1.00	0.50	0.27	0.24	0.21	0.19	0.00	0.00	0.00	0.00	0.00	0.03
September	1.00	0.50	0.26	0.21	0.18	0.14	0.00	0.00	0.00	0.00	0.00	0.04
October	1.00	0.55	0.53	0.51	0.48	0.46	0.45	0.45	0.00	0.00	0.00	0.04
November	1.00	3.40	1.59	1.01	0.84	0.74	0.68	0.64	0.09	0.04	0.02	0.09
December	1.00	4.53	1.76	1.23	1.04	0.93	0.86	0.81	0.04	0.04	0.04	0.14

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	0.39	0.53	0.58	0.61	0.59	0.54	0.49
February	0.27	0.58	0.62	0.59	0.56	0.55	0.52
March	0.42	0.70	0.72	0.67	0.64	0.61	0.59
April	0.15	0.26	0.29	0.26	0.24	0.21	0.20
May	0.17	0.24	0.24	0.22	0.19	0.17	0.15
June	0.15	0.19	0.18	0.18	0.18	0.14	0.13
July	0.11	0.19	0.19	0.18	0.17	0.16	0.16
August	0.10	0.19	0.18	0.17	0.17	0.16	0.15
September	0.12	0.18	0.16	0.17	0.14	0.08	0.00
October	0.14	0.34	0.39	0.40	0.40	0.40	0.40
November	0.32	0.54	0.52	0.51	0.50	0.48	0.48
December	0.44	0.59	0.62	0.62	0.62	0.61	0.61

All PVs configuration D is 375 kWp

Table A 42: Scenario 11 (N-H-24-1) Monthly energy charges in Year 1 for various DES component sizes.

Monthly energy charges (NOK)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	369 936	369 782	369 205	368 773	368 866	368 804	368 449	368 423	365 265	360 636	352 013	336 562
February	305 250	305 166	305 033	304 971	305 247	305 626	306 279	307 242	296 599	288 132	272 812	250 905
March	401 932	401 768	401 303	400 748	400 815	401 599	402 916	404 900	387 087	372 339	344 207	300 594
April	329 711	329 297	328 177	327 052	327 107	326 585	326 060	326 167	312 746	296 389	266 877	217 889
May	394 795	394 384	392 694	391 792	391 094	391 335	391 339	391 439	372 543	350 826	311 737	247 455
June	386 411	386 156	385 209	384 495	384 199	383 819	382 790	382 422	368 472	350 583	316 144	253 981
July	394 859	394 847	395 209	395 504	395 578	395 661	396 495	396 654	374 299	353 947	318 353	257 978
August	325 357	325 055	324 488	324 142	323 504	323 138	318 558	317 697	310 889	296 643	271 376	229 075
September	469 282	468 797	467 494	466 773	466 850	466 906	463 175	462 452	451 018	433 116	402 817	354 845
October	383 887	383 746	383 267	382 997	383 210	383 476	384 951	385 843	374 048	364 231	345 435	313 897
November	331 815	331 629	331 013	330 899	330 830	330 700	330 949	331 517	327 035	322 254	312 769	296 479
December	139 373	139 223	138 617	137 688	137 178	137 458	137 697	138 094	136 383	133 414	128 911	122 643

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + DESS (D) 1000 kWh	PV Buy + DESS (D) 1500 kWh	PV Buy + DESS (D) 2000 kWh	PV Buy + DESS (D) 2500 kWh	PV Buy + DESS (D) 3000 kWh
January	360 455	359 895	359 397	359 368	359 334	358 954	358 777
February	287 954	287 761	287 783	288 040	288 386	289 036	289 745
March	372 100	371 430	370 894	370 575	370 799	371 455	372 418
April	295 844	294 269	293 689	293 553	293 446	293 005	293 157
May	350 282	348 743	347 931	348 061	348 078	347 859	347 514
June	350 309	349 613	348 595	348 583	348 625	347 774	347 791
July	353 784	354 077	354 040	354 164	354 514	355 070	355 418
August	296 238	295 891	294 873	293 872	293 519	293 604	293 554
September	432 506	431 364	430 679	431 216	431 453	429 654	426 456
October	364 037	363 583	363 337	363 540	363 910	364 378	366 181
November	322 064	321 422	321 283	320 978	320 829	321 026	321 650
December	133 248	132 554	131 755	131 296	131 591	131 803	132 202

All PVs configuration D is 375 kWp

Table A 43: Scenario 11 (N-H-24-1) The change in monthly energy charges in Year 1 for various DES component sizes.

Change in energy charge from Base case (NOK)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	0	155	731	1163	1071	1133	1487	1513	4672	9300	17924	33375
February	0	84	217	279	3	-376	-1029	-1992	8651	17118	32438	54345
March	0	164	630	1185	1117	333	-983	-2968	14845	29594	57725	101338
April	0	414	1534	2659	2603	3126	3651	3544	16965	33322	62834	111821
May	0	411	2101	3004	3702	3460	3456	3356	22252	43970	83059	147340
June	0	255	1202	1916	2212	2592	3621	3989	17939	35828	70267	132430
July	0	13	-350	-645	-719	-802	-1636	-1795	20560	40912	76506	136881
August	0	303	869	1215	1853	2219	6799	7660	14468	28715	53982	96282
September	0	485	1788	2510	2432	2376	6108	6830	18264	36166	66466	114438
October	0	141	620	890	678	411	-1063	-1955	9840	19657	38453	69991
November	0	186	802	916	985	1115	866	298	4780	9561	19046	35336
December	0	150	756	1685	2195	1915	1676	1279	2990	5959	10462	16730

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	9482	10041	10540	10568	10602	10982	11159
February	17296	17489	17467	17210	16864	16214	15505
March	29832	30503	31038	31357	31134	30478	29515
April	33867	35442	36022	36158	36265	36706	36554
May	44513	46052	46864	46734	46717	46937	47281
June	36102	36798	37816	37828	37786	38637	38620
July	41075	40783	40819	40695	40346	39789	39441
August	29119	29466	30485	31485	31838	31753	31804
September	36776	37918	38603	38066	37829	39628	42826
October	19850	20305	20550	20347	19977	19509	17706
November	9751	10393	10532	10837	10986	10789	10165
December	6125	6819	7618	8077	7782	7570	7171

All PVs configuration D is 375 kWp

Table A 44: Scenario 11 (N-H-24-1) The relative improvement in monthly energy charges per CAPEX in Year 1 for various DES component sizes.

Relative improvement in energy charge per CAPEX compared to Base case (1 = Break even)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	0.14	0.14	0.11	0.07	0.05	0.06	0.05	0.84	0.83	0.80	0.73
February	1.00	0.08	0.04	0.03	0.00	-0.02	-0.04	-0.06	1.55	1.53	1.45	1.19
March	1.00	0.15	0.12	0.11	0.07	0.02	-0.04	-0.09	2.66	2.65	2.58	2.21
April	1.00	0.38	0.28	0.25	0.16	0.14	0.14	0.11	3.04	2.98	2.81	2.44
May	1.00	0.38	0.39	0.28	0.23	0.16	0.13	0.10	3.98	3.93	3.72	3.22
June	1.00	0.24	0.22	0.18	0.14	0.12	0.13	0.12	3.21	3.21	3.14	2.89
July	1.00	0.01	-0.06	-0.06	-0.04	-0.04	-0.06	-0.06	3.68	3.66	3.42	2.99
August	1.00	0.28	0.16	0.11	0.11	0.10	0.25	0.24	2.59	2.57	2.41	2.10
September	1.00	0.45	0.33	0.23	0.15	0.11	0.23	0.21	3.27	3.24	2.97	2.50
October	1.00	0.13	0.11	0.08	0.04	0.02	-0.04	-0.06	1.76	1.76	1.72	1.53
November	1.00	0.17	0.15	0.08	0.06	0.05	0.03	0.01	0.86	0.86	0.85	0.77
December	1.00	0.14	0.14	0.16	0.14	0.09	0.06	0.04	0.53	0.53	0.47	0.37

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	0.77	0.61	0.48	0.39	0.32	0.29	0.26
February	1.41	1.05	0.79	0.63	0.51	0.42	0.36
March	2.43	1.84	1.41	1.14	0.95	0.80	0.68
April	2.76	2.14	1.64	1.32	1.11	0.96	0.84
May	3.63	2.78	2.13	1.71	1.42	1.23	1.08
June	2.94	2.22	1.72	1.38	1.15	1.01	0.89
July	3.35	2.46	1.86	1.49	1.23	1.04	0.90
August	2.38	1.78	1.39	1.15	0.97	0.83	0.73
September	3.00	2.29	1.76	1.39	1.15	1.04	0.98
October	1.62	1.22	0.93	0.74	0.61	0.51	0.41
November	0.80	0.63	0.48	0.40	0.33	0.28	0.23
December	0.50	0.41	0.35	0.29	0.24	0.20	0.16

All PVs configuration D is 375 kWp

Table A 45: Scenario 11 (N-H-24-1) Monthly total electricity costs in Year 1 for various DES component sizes.

Monthly total electricity costs (NOK) *(Includes monthly fixed charge of NOK 568.20)*

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	468 871	464 746	459 758	455 284	451 449	448 833	447 352	446 058	463 865	458 902	449 610	430 258
February	401 701	398 295	391 854	388 899	386 686	384 748	383 203	381 694	393 050	384 583	369 263	344 034
March	500 867	496 451	489 354	485 286	482 413	480 784	479 564	479 013	486 022	471 273	443 142	394 431
April	360 398	358 422	354 903	353 504	352 178	351 483	350 872	350 375	343 396	327 004	297 420	246 627
May	426 258	425 042	422 335	420 416	419 540	419 250	418 989	418 735	403 108	381 267	341 933	275 879
June	417 874	417 169	415 248	413 959	413 087	412 354	411 679	411 311	399 379	381 263	346 508	283 002
July	426 322	425 992	425 336	424 658	424 112	424 018	423 968	423 684	405 650	385 186	349 368	287 044
August	356 820	355 979	354 483	352 986	351 549	350 433	350 101	349 240	342 352	328 106	302 839	259 025
September	500 745	499 721	497 533	496 015	495 384	495 440	494 718	493 996	482 481	464 579	434 279	384 618
October	483 319	482 585	479 841	476 880	474 827	472 970	472 179	470 805	473 479	463 662	444 866	411 320
November	430 253	426 397	420 883	418 377	415 649	413 132	411 138	409 183	424 976	420 195	410 710	390 966
December	208 003	202 961	197 713	193 042	189 023	185 927	183 108	180 453	204 772	201 564	196 580	185 004

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + DESS (D) 1000 kWh	PV Buy + DESS (D) 1500 kWh	PV Buy + DESS (D) 2000 kWh	PV Buy + DESS (D) 2500 kWh	PV Buy + DESS (D) 3000 kWh
January	454 573	450 025	445 529	441 573	438 801	437 293	436 130
February	381 083	374 573	370 523	368 347	366 409	364 587	363 374
March	465 937	458 786	453 935	451 169	448 856	446 976	445 685
April	324 711	320 704	317 983	317 071	316 360	315 795	315 294
May	379 702	376 199	374 164	373 498	373 161	372 853	372 509
June	379 994	377 971	376 086	374 993	374 327	373 830	373 671
July	383 912	382 434	381 367	380 721	380 393	380 241	379 793
August	326 454	324 249	322 312	320 554	319 451	318 952	318 548
September	462 456	459 898	458 682	458 158	458 218	458 189	457 999
October	461 744	457 324	454 176	452 087	450 200	448 429	447 993
November	416 551	410 950	408 201	405 482	402 946	401 215	399 035
December	196 498	191 372	186 719	182 946	179 810	177 214	174 329

All PVs configuration D is 375 kWp

Table A 46: Scenario 11 (N-H-24-1) The change in monthly total electricity costs in Year 1 for various DES component sizes.

Change in total electricity costs from Base case (NOK)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	0	4125	9113	13587	17422	20038	21519	22813	5006	9969	19261	38613
February	0	3405	9847	12801	15014	16953	18497	20006	8651	17118	32438	57666
March	0	4417	11513	15581	18455	20083	21303	21854	14845	29594	57725	106436
April	0	1975	5495	6894	8219	8914	9526	10023	17001	33394	62978	113771
May	0	1216	3924	5842	6719	7008	7270	7524	23151	44991	84325	150380
June	0	705	2626	3915	4787	5520	6195	6563	18495	36610	71366	134872
July	0	330	986	1664	2210	2304	2354	2638	20672	41136	76954	139278
August	0	842	2337	3834	5271	6387	6719	7580	14468	28715	53982	97795
September	0	1024	3212	4730	5361	5305	6027	6749	18264	36166	66466	116127
October	0	734	3478	6438	8492	10349	11140	12514	9840	19657	38453	71999
November	0	3856	9369	11875	14604	17121	19114	21070	5277	10057	19543	39287
December	0	5042	10290	14961	18980	22075	24895	27550	3230	6439	11423	22999

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	14298	18846	23342	27298	30070	31578	32741
February	20617	27127	31178	33354	35292	37114	38327
March	34930	42081	46932	49699	52011	53891	55182
April	35687	39693	42415	43327	44037	44602	45103
May	46557	50060	52094	52760	53098	53405	53750
June	37880	39903	41788	42881	43547	44044	44203
July	42411	43888	44955	45601	45929	46081	46529
August	30366	32572	34508	36266	37369	37868	38272
September	38289	40847	42063	42588	42527	42557	42746
October	21575	25994	29143	31232	33119	34890	35326
November	13702	19302	22052	24771	27307	29037	31218
December	11505	16631	21284	25057	28193	30789	33674

All PVs configuration D is 375 kWp

Table A 47: Scenario 11 (N-H-24-1) The relative improvement in monthly total electricity costs per CAPEX in Year 1 for various DES component sizes.

Relative improvement in total electricity cost per CAPEX compared to Base case (1 = Break even)

Month of Year 1	Base case (A)	BESS (B) 100 kWh	BESS (B) 500 kWh	BESS (B) 1000 kWh	BESS (B) 1500 kWh	BESS (B) 2000 kWh	BESS (B) 2500 kWh	BESS (B) 3000 kWh	PV Buy (C) 187.5 kWp	PV Buy (C) 375 kWp	PV Buy (C) 750 kWp	PV Buy (C) 1500 kWp
January	1.00	3.82	1.69	1.26	1.07	0.93	0.80	0.70	0.90	0.89	0.86	0.84
February	1.00	3.15	1.82	1.18	0.93	0.78	0.68	0.62	1.55	1.53	1.45	1.26
March	1.00	4.09	2.13	1.44	1.14	0.93	0.79	0.67	2.66	2.65	2.58	2.32
April	1.00	1.83	1.02	0.64	0.51	0.41	0.35	0.31	3.04	2.99	2.82	2.48
May	1.00	1.13	0.73	0.54	0.41	0.32	0.27	0.23	4.14	4.02	3.77	3.28
June	1.00	0.65	0.49	0.36	0.30	0.26	0.23	0.20	3.31	3.28	3.19	2.95
July	1.00	0.31	0.18	0.15	0.14	0.11	0.09	0.08	3.70	3.68	3.44	3.04
August	1.00	0.78	0.43	0.35	0.33	0.30	0.25	0.23	2.59	2.57	2.41	2.14
September	1.00	0.95	0.59	0.44	0.33	0.25	0.22	0.21	3.27	3.24	2.97	2.54
October	1.00	0.68	0.64	0.60	0.52	0.48	0.41	0.39	1.76	1.76	1.72	1.57
November	1.00	3.57	1.73	1.10	0.90	0.79	0.71	0.65	0.94	0.90	0.87	0.86
December	1.00	4.66	1.90	1.38	1.17	1.02	0.92	0.85	0.58	0.58	0.51	0.50

Month of Year 1	PV Buy + BESS (D) 100 kWh	PV Buy + BESS (D) 500 kWh	PV Buy + BESS (D) 1000 kWh	PV Buy + BESS (D) 1500 kWh	PV Buy + BESS (D) 2000 kWh	PV Buy + BESS (D) 2500 kWh	PV Buy + BESS (D) 3000 kWh
January	1.17	1.14	1.06	1.00	0.92	0.83	0.75
February	1.68	1.64	1.42	1.22	1.08	0.97	0.88
March	2.85	2.54	2.13	1.81	1.59	1.41	1.27
April	2.91	2.39	1.93	1.58	1.34	1.17	1.03
May	3.80	3.02	2.37	1.93	1.62	1.40	1.23
June	3.09	2.41	1.90	1.57	1.33	1.15	1.01
July	3.46	2.65	2.04	1.66	1.40	1.21	1.07
August	2.48	1.96	1.57	1.32	1.14	0.99	0.88
September	3.12	2.46	1.91	1.55	1.30	1.11	0.98
October	1.76	1.57	1.33	1.14	1.01	0.91	0.81
November	1.12	1.16	1.00	0.90	0.83	0.76	0.72
December	0.94	1.00	0.97	0.91	0.86	0.81	0.77

All PVs configuration D is 375 kWp

A.11.3 Buying vs leasing PVs – Cash Flows

These figures show the nominal and discounted cash flows for buying and leasing new solar PVs.

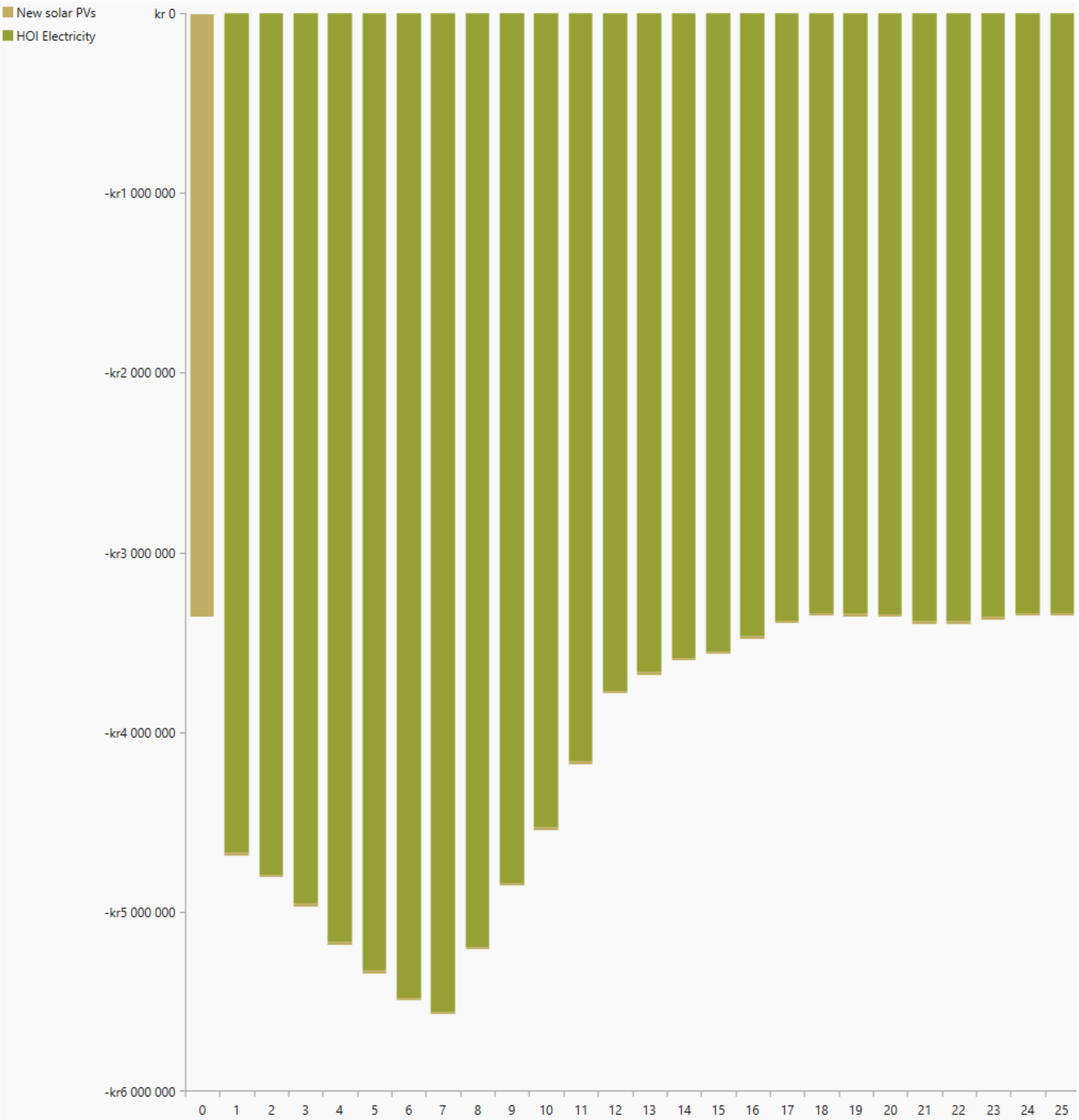


Figure A 1: N-H-24-1-8-C (PV Buy) - Nominal cash flow.

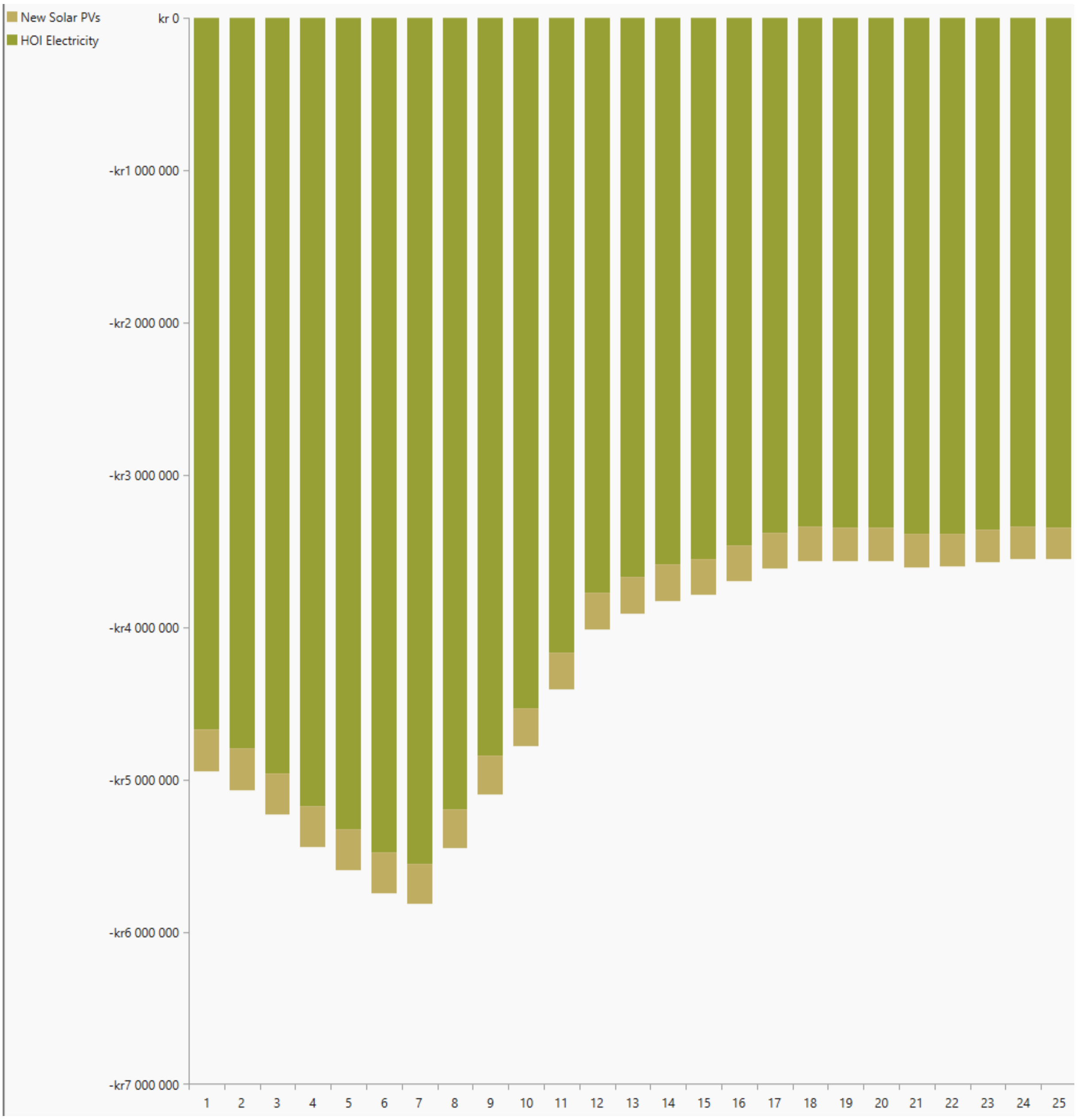


Figure A 2: N-H-24-1-8-E (PV Leasing) - Nominal cash flow.

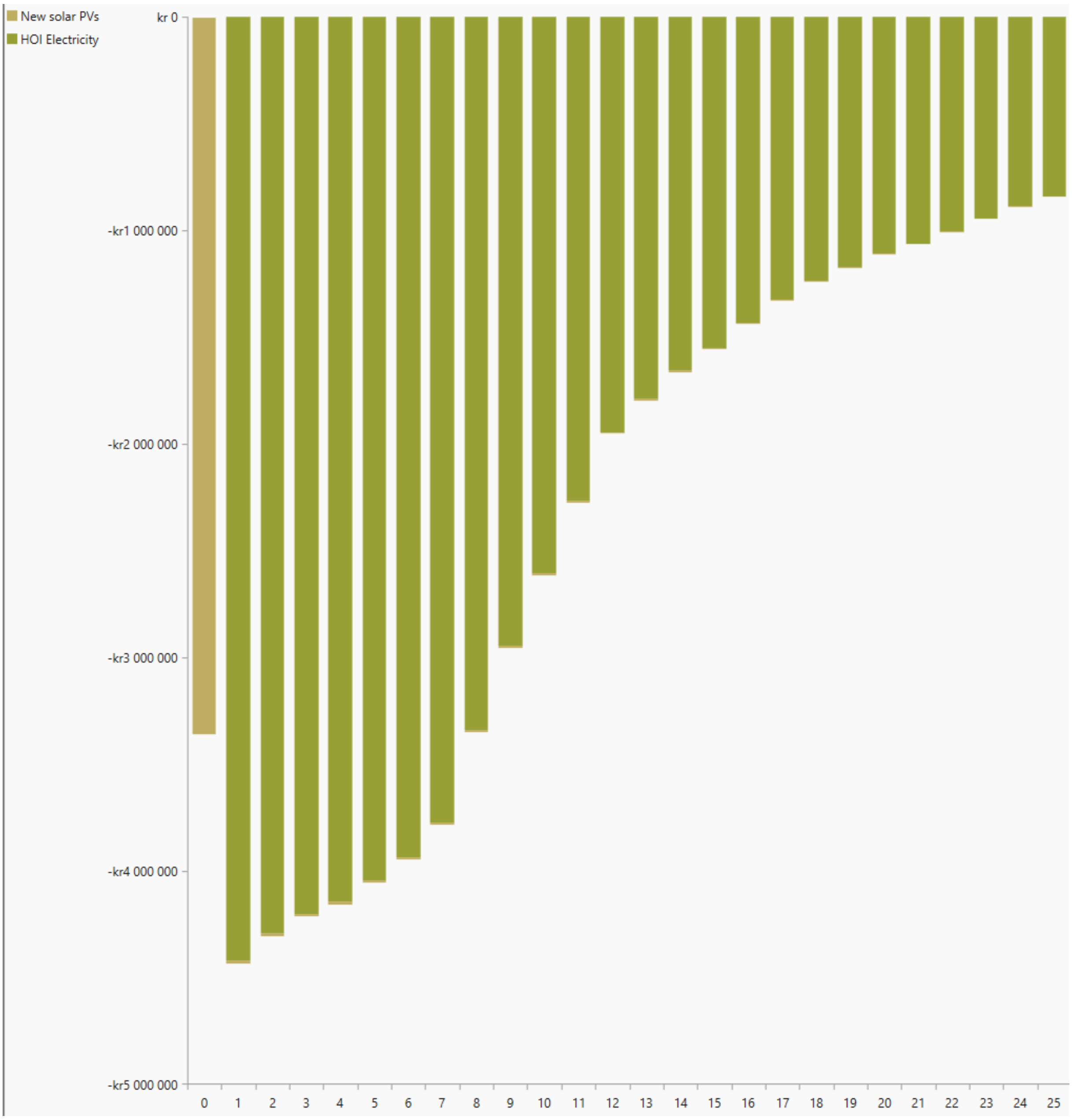


Figure A 3: N-H-24-1-8-C (PV Buy) - Discounted cash flow.

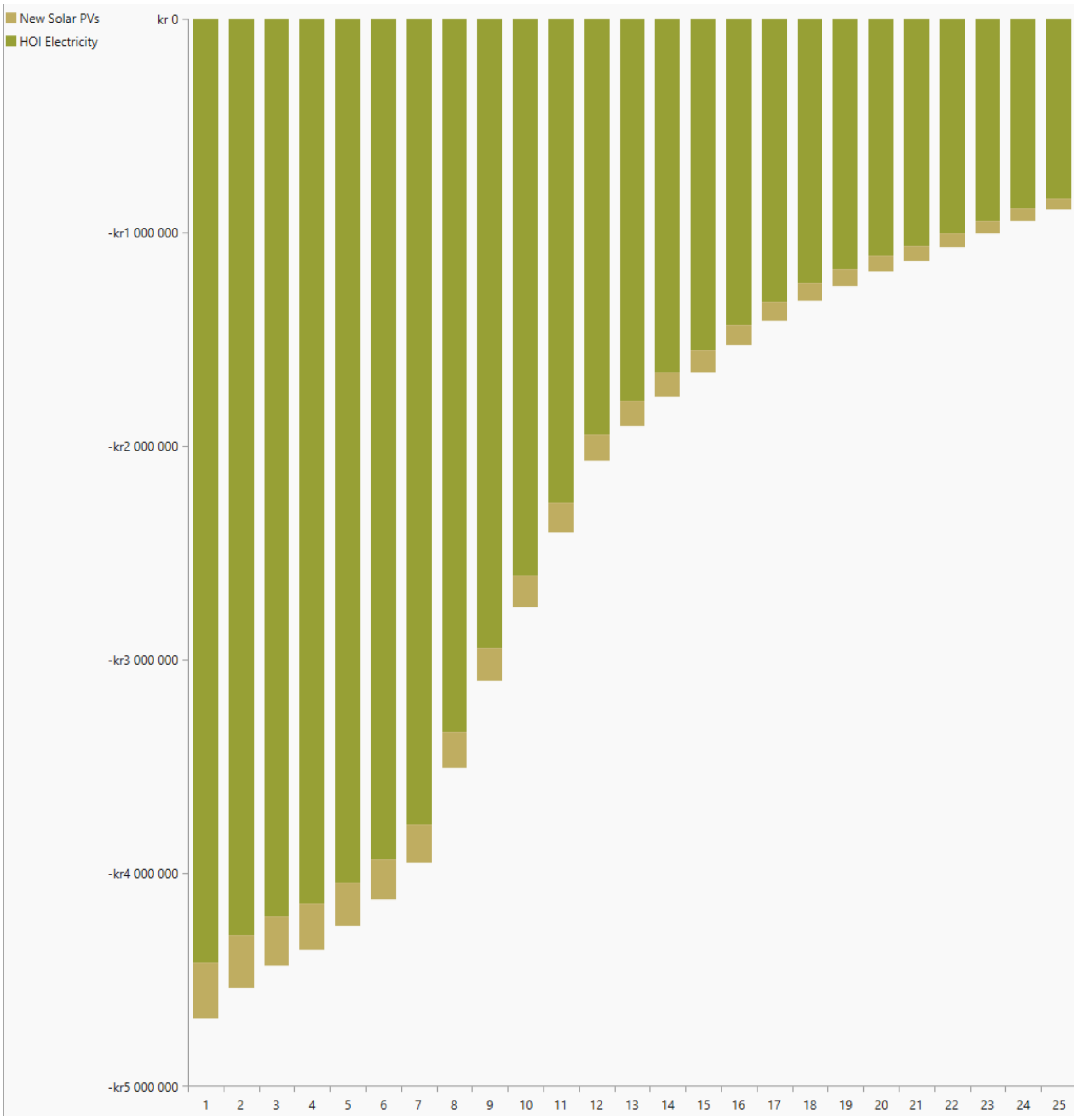


Figure A 4: N-H-24-1-8-C (PV Buy) - Discounted cash flow.

A.12 Scenario 12 – N-H-24-S

Prognosis: NVE HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2024

Table A 48: Scenario 12 (N-H-24-S) Simulation configurations overview.

N-H-24-S	Discount rates	Sensitivity
3-E	3,566 %	1
6-E	6 %	1
8-E	8 %	1
10-E	10 %	1
12-E	12 %	1
3-C	3,566 %	1
6-C	6 %	1
8-C	8 %	1
10-C	10 %	0,9
12-C	12 %	0,8
3-B	3,566 %	0,85
6-B	6 %	0,65
8-B	8 %	0,55
10-B	10 %	0,5
12-B	12 %	0,45

Table A 49: Scenario 12 (N-H-24-S) Economic metrics.

N-H-24-S	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-E	94,5	1				
6-E	73,8	1,03				
8-E	61,6	1,05				
10-E	52,3	1,06				
12-E	45,1	1,08				
3-C	93,1	0,986	3,8	6,8	10,48	11,54
6-C	73,4	1,02	3,8	6,8	10,48	14,59
8-C	61,8	1,05	3,8	6,8	10,48	19,48
10-C	52,7	1,07	4,7	8,1	9,36	21,86
12-C	45,5	1,09	5,8	9,7	8,32	24,01
3-B	95,3	1,01	0,6	1,4	19,86	24,97
6-B	74,5	1,04	2,1	4,5	9,42	20,7
8-B	62,2	1,06	3,2	6,8	8,01	19,4
10-B	52,8	1,07	3,9	8,2	7,3	20,85
12-B	45,6	1,09	4,7	9,9	6,56	21,62

Table A 50: Scenario 12 (N-H-24-S) Costs and present worth.

N-H-24-S	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-E	4,47	0	666 069	3,56	4 137 028	4691	808 277
6-E	4,59	0	683 334	3,65	4 137 028	4691	677 802
8-E	4,67	0	696 225	3,72	4 137 028	4691	592 402
10-E	4,75	0	707 709	3,78	4 137 028	4691	521 787
12-E	4,81	0	717 684	3,84	4 137 028	4691	462 737
3-C	4,24	3,35	666 069	3,56	4 137 028	4691	2 273 710
6-C	4,35	3,35	683 334	3,65	4 137 028	4691	1 051 843
8-C	4,44	3,35	696 225	3,72	4 137 028	4691	328 622
10-C	4,51	3,02	707 709	3,78	4 137 028	4691	113 019
12-C	4,57	2,68	717 684	3,84	4 137 028	4691	20 761
3-B	4,5	0,28	646 905	3,84	4 465 694	0	1 512
6-B	4,61	0,21	663 699	3,94	4 465 694	0	11 631
8-B	4,7	0,18	676 247	4,01	4 465 694	0	11 887
10-B	4,78	0,16	687 432	4,08	4 465 694	0	3 557
12-B	4,85	0,15	697 153	4,14	4 465 694	0	559

A.13 Scenario 13 - S-L-30-1

Prognosis: Statnett LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 51: Scenario 13 (S-L-30-1) Simulation configurations overview.

S-L-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A

10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 52: Scenario 13 (S-L-30-1) Economic metrics.

S-L-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	27,66	0,293				
3-B	27,93	0,296				
3-C	28,16	0,298				
3-D	28,40	0,301				
6-A	21,60	0,301				
6-B	21,86	0,304				
6-C	22,43	0,312				
6-D	22,66	0,315				
8-A	18,03	0,307				
8-B	18,28	0,311				
8-C	19,06	0,324				
8-D	19,28	0,328				
10-A	15,33	0,312				
10-B	15,57	0,317				
10-C	16,51	0,336				
10-D	16,73	0,340				
12-A	13,25	0,317				
12-B	13,48	0,322				
12-C	14,54	0,347				
12-D	14,75	0,353				

Table A 53: Scenario 13 (S-L-30-1) Costs and present worth.

S-L-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	1,31	0	194 674	1,11	4 460 213	0	0
3-B	1,31	0,219	187 711	1,11	4 462 039	0	-271 990
3-C	1,24	2,025	193 267	1,03	4 137 028	4691	-504 530
3-D	1,24	2,244	185 006	1,03	4 136 727	2255	-741 250
6-A	1,34	0	199 620	1,14	4 460 213	0	0
6-B	1,34	0,219	192 478	1,14	4 462 039	0	-256 360
6-C	1,27	2,025	198 167	1,06	4 137 028	4691	-833 310
6-D	1,27	2,244	189 696	1,06	4 136 727	2255	-1 062 170
8-A	1,37	0	203 466	1,16	4 460 213	0	0

8-B	1,37	0,219	196 187	1,16	4 462 039	0	-245 760
8-C	1,29	2,025	201 977	1,08	4 137 028	4691	-1 027 310
8-D	1,29	2,244	193 343	1,08	4 136 727	2255	-1 250 120
10-A	1,39	0	207 034	1,18	4 460 213	0	0
10-B	1,39	0,219	199 630	1,18	4 462 039	0	-237 220
10-C	1,31	2,025	205 512	1,10	4 137 028	4691	-1 174 670
10-D	1,31	2,244	196 727	1,10	4 136 727	2255	-1 392 370
12-A	1,41	0	210 276	1,20	4 460 213	0	0
12-B	1,41	0,219	202 761	1,20	4 462 039	0	-230 520
12-C	1,33	2,025	208 726	1,12	4 137 028	4691	-1 288 810
12-D	1,33	2,244	199 803	1,11	4 136 727	2255	-1 502 440

A.14 Scenario 14 – S-B-30-1

Prognosis: Statnett BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 54: Scenario 14 (S-B-30-1) Simulation configurations overview.

S-B-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 55: Scenario 14 (S-B-30-1) Economic metrics.

S-B-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	38,7	0,41				
3-B	38,9	0,413				
3-C	38,5	0,408	1,1	2,1	18,94	22,27
3-D	38,7	0,41	0,7	1,4	21,2	24,74
6-A	29,8	0,416				
6-B	30,1	0,419				
6-C	30,2	0,42				
6-D	30,3	0,422				
8-A	24,7	0,42				
8-B	24,9	0,423				
8-C	25,3	0,43				
8-D	25,5	0,433				
10-A	20,8	0,423				
10-B	21	0,428				
10-C	21,6	0,44				
10-D	21,8	0,444				
12-A	17,8	0,427				
12-B	18	0,432				
12-C	18,8	0,45				
12-D	19	0,455				

Table A 56: Scenario 14 (S-B-30-1) Costs and present worth.

S-B-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	1,83	0	272 263	1,56	4 460 212	0	0
3-B	1,83	0,22	262 525	1,56	4 463 192	0	-208 290
3-C	1,73	2,03	270 302	1,45	4 137 028	4691	186 717
3-D	1,72	2,24	258 743	1,44	4 137 820	2255	26 188
6-A	1,85	0	275 828	1,58	4 460 212	0	0
6-B	1,85	0,22	265 960	1,58	4 463 192	0	-208 770
6-C	1,75	2,03	273 828	1,46	4 137 028	4691	-316 250
6-D	1,74	2,24	262 115	1,46	4 137 820	2255	-488 080
8-A	1,87	0	278 542	1,59	4 460 212	0	0
8-B	1,87	0,22	268 576	1,59	4 463 192	0	-207 430
8-C	1,76	2,03	276 511	1,48	4 137 028	4691	-610 040
8-D	1,76	2,24	264 681	1,48	4 137 820	2255	-786 850
10-A	1,89	0	281 003	1,61	4 460 212	0	0
10-B	1,89	0,22	270 952	1,61	4 463 192	0	-205 730
10-C	1,78	2,03	278 945	1,49	4 137 028	4691	-831 150
10-D	1,78	2,24	267 010	1,49	4 137 820	2255	-1 011 000

12-A	1,9	0	283 183	1,62	4 460 212	0	0
12-B	1,9	0,22	273 058	1,62	4 463 192	0	-204 160
12-C	1,79	2,03	281 100	1,5	4 137 028	4691	-1 000 820
12-D	1,79	2,24	269 071	1,5	4 137 820	2255	-1 182 720

A.15 Scenario 15 - S-H-30-1

Prognosis: Statnett HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 57: Scenario 15 (S-H-30-1) Simulation configurations overview.

S-H-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 58: Scenario 15 (S-H-30-1) Economic metrics.

S-H-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	49,2	0,522				
3-B	49,4	0,524				
3-C	48,4	0,513	2,7	4,6	14,11	15,92
3-D	48,5	0,514	2,3	4,1	15,61	17,57
6-A	38	0,529				
6-B	38,2	0,532				

6-C	37,8	0,526	2,7	4,6	14,11	21,23
6-D	37,9	0,528	2,3	4,1	15,61	23,78
8-A	31,4	0,535				
8-B	31,6	0,537				
8-C	31,6	0,537				
8-D	31,8	0,54				
10-A	26,5	0,539				
10-B	26,7	0,543				
10-C	27	0,549				
10-D	27,1	0,552				
12-A	22,7	0,544				
12-B	22,9	0,548				
12-C	23,4	0,56				
12-D	23,6	0,564				

Table A 59: Scenario 15 (S-H-30-1) Costs and present worth.

S-H-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	2,33	0	346 556	1,98	4 460 212	0	0
3-B	2,33	0,22	334 166	1,98	4 463 926	0	-153 020
3-C	2,19	2,03	344 062	1,84	4 137 028	4691	840 991
3-D	2,19	2,24	329 350	1,84	4 138 530	2255	756 464
6-A	2,36	0	351 144	2,01	4 460 212	0	0
6-B	2,36	0,22	338 586	2,01	4 463 926	0	-165 950
6-C	2,22	2,03	348 599	1,86	4 137 028	4691	195 190
6-D	2,22	2,24	333 690	1,86	4 138 530	2255	76 112
8-A	2,38	0	354 683	2,03	4 460 212	0	0
8-B	2,38	0,22	341 999	2,03	4 463 926	0	-171 930
8-C	2,24	2,03	352 099	1,88	4 137 028	4691	-186 410
8-D	2,24	2,24	337 037	1,88	4 138 530	2255	-319 450
10-A	2,41	0	357 942	2,05	4 460 212	0	0
10-B	2,4	0,22	345 149	2,05	4 463 926	0	-175 740
10-C	2,27	2,03	355 322	1,9	4 137 028	4691	-473 400
10-D	2,26	2,24	340 121	1,9	4 138 530	2255	-616 230
12-A	2,43	0	360 882	2,07	4 460 212	0	0
12-B	2,42	0,22	347 988	2,06	4 463 926	0	-178 370
12-C	2,28	2,03	358 231	1,92	4 137 028	4691	-693 450
12-D	2,28	2,24	342 903	1,91	4 138 530	2255	-843 500

A.16 Scenario 16 - N-L-30-1

Prognosis: NVE LOW

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 60: Scenario 16 (N-L-30-1) Simulation configurations overview.

N-L-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 61: Scenario 16 (N-L-30-1) Economic metrics.

N-L-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	30,92	0,328				
3-B	31,17	0,331				
3-C	31,22	0,331	1,7	4,1	13,05	15,31
3-D	31,43	0,333	1,3	3,3	15,54	18,38
6-A	24,25	0,338				
6-B	24,49	0,341				
6-C	24,91	0,347	1,7	4,1	13,05	22,9
6-D	25,12	0,350				
8-A	20,34	0,346				
8-B	20,58	0,350				
8-C	21,23	0,360				
8-D	21,43	0,364				
10-A	17,40	0,354				
10-B	17,62	0,359				
10-C	18,44	0,375				
10-D	18,65	0,379				
12-A	15,13	0,362				
12-B	15,35	0,367				

12-C	16,30	0,390
12-D	16,50	0,395

Table A 62: Scenario 16 (N-L-30-1) Costs and present worth.

N-L-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energ y sold (kWh)	Present worth (NOK)
3-A	1,46	0	217 477	1,25	4 460 213	0	0
3-B	1,46	0,219	209 720	1,24	4 462 423	0	-253 120
3-C	1,38	2,025	215 911	1,16	4 137 028	4691	-299 690
3-D	1,38	2,244	206 681	1,15	4 137 096	2255	-513 100
6-A	1,51	0	223 924	1,28	4 460 213	0	0
6-B	1,51	0,219	215 939	1,28	4 462 423	0	-241 190
6-C	1,42	2,025	222 300	1,19	4 137 028	4691	-666 800
6-D	1,42	2,244	212 795	1,19	4 137 096	2255	-876 840
8-A	1,54	0	229 327	1,31	4 460 213	0	0
8-B	1,54	0,219	221 153	1,31	4 462 423	0	-232 620
8-C	1,46	2,025	227 656	1,22	4 137 028	4691	-882 010
8-D	1,46	2,244	217 921	1,22	4 137 096	2255	-1 088 460
10-A	1,58	0	234 701	1,34	4 460 213	0	0
10-B	1,58	0,219	226 342	1,34	4 462 423	0	-225 520
10-C	1,49	2,025	232 984	1,25	4 137 028	4691	-1 044 650
10-D	1,49	2,244	223 021	1,25	4 137 096	2255	-1 247 750
12-A	1,61	0	239 950	1,37	4 460 213	0	0
12-B	1,61	0,219	231 413	1,37	4 462 423	0	-219 870
12-C	1,52	2,025	238 189	1,28	4 137 028	4691	-1 170 110
12-D	1,52	2,244	228 003	1,27	4 137 096	2255	-1 370 420

A.17 Scenario 17 – N-B-30-1

Prognosis: NVE BASIS

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 63: Scenario 17 (N-B-30-1) Simulation configurations overview.

N-B-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A

6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A
12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 64: Scenario 17 (N-B-30-1) Economic metrics.

N-B-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	56,7	0,601				
3-B	56,8	0,602				
3-C	55,3	0,587	3,7	6,6	11,53	12,76
3-D	55,4	0,587	3,3	6	11,79	14,12
6-A	44,2	0,616				
6-B	44,4	0,618				
6-C	43,6	0,607	3,7	6,6	11,53	15,96
6-D	43,7	0,609	3,3	6	11,79	17,65
8-A	37	0,628				
8-B	37,1	0,631				
8-C	36,8	0,625	3,7	6,6	11,53	20,8
8-D	36,9	0,627	3,3	6	11,79	23,49
10-A	31,5	0,641				
10-B	31,7	0,644				
10-C	31,7	0,644				
10-D	31,8	0,646				
12-A	27,3	0,653				
12-B	27,7	0,662				
12-C	27,5	0,657				
12-D	27,8	0,665				

Table A 65: Scenario 17 (N-B-30-1) Costs and present worth.

N-B-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	2,68	0	398 612	2,28	4 460 212	0	0

3-B	2,68	0,22	384 392	2,28	4 464 248	0	-116 930
3-C	2,52	2,03	395 745	2,12	4 137 028	4691	1 315 420
3-D	2,25	2,24	378 827	2,11	4 138 858	2255	1 267 920
6-A	2,75	0	408 445	2,34	4 460 212	0	0
6-B	2,74	0,22	393 877	2,34	4 464 248	0	-134 990
6-C	2,59	2,03	405 487	2,17	4 137 028	4691	586 590
6-D	2,58	2,24	388 150	2,17	4 138 858	2255	506 210
8-A	2,8	0	416 702	2,39	4 460 212	0	0
8-B	2,8	0,22	401 848	2,38	4 464 248	0	-144 110
8-C	2,64	2,03	413 670	2,21	4 137 028	4691	160 860
8-D	2,63	2,24	395 982	2,21	4 138 858	2255	62 640
10-A	2,86	0	424 933	2,43	4 460 212	0	0
10-B	2,69	2,03	421 828	2,26	4 464 248	0	-150 350
10-C	2,85	0,22	409 796	2,43	4 137 028	4691	-159 770
10-D	2,68	2,24	403 790	2,25	4 138 858	2255	-270 810
12-A	2,91	0	432 990	2,48	4 460 212	0	0
12-B	2,74	2,03	429 815	2,3	4 137 028	0	-154 910
12-C	2,91	0,22	417 580	2,48	4 137 028	4691	-406 160
12-D	2,73	2,24	411 435	2,3	4 138 858	2255	-526 830

A.18 Scenario 18 – N-H-30-1

Prognosis: NVE HIGH

Inflation: 2,2%.

Project lifetime: 25 years

Starting year: 2030

Table A 66: Scenario 18 (N-H-30-1) Simulation configurations overview.

N-H-30-1	Discount rates	Sensitivity
3-A	3,566 %	N/A
3-B	3,566 %	N/A
3-C	3,566 %	N/A
3-D	3,566 %	N/A
6-A	6 %	N/A
6-B	6 %	N/A
6-C	6 %	N/A
6-D	6 %	N/A
8-A	8 %	N/A
8-B	8 %	N/A
8-C	8 %	N/A
8-D	8 %	N/A
10-A	10 %	N/A
10-B	10 %	N/A
10-C	10 %	N/A
10-D	10 %	N/A

12-A	12 %	N/A
12-B	12 %	N/A
12-C	12 %	N/A
12-D	12 %	N/A

Table A 67: Scenario 18 (N-H-30-1) Economic metrics.

N-H-30-1	NPC (M NOK)	LCOE (NOK/kWh)	ROI (%)	IRR (%)	Simple payback (years)	Discounted payback (years)
3-A	84,7	0,899				
3-B	84,7	0,898	1,3	2,7	10,7	11,85
3-C	81,6	0,865	7,8	12,6	6,86	7,31
3-D	81,5	0,864	7,3	12,2	6,94	7,4
6-A	66	0,92				
6-B	66,1	0,92				
6-C	64,1	0,892	7,8	12,6	6,86	8,31
6-D	64	0,891	7,3	12,2	6,94	8,42
8-A	55,1	0,938				
8-B	55,2	0,938				
8-C	53,8	0,914	7,8	12,6	6,86	9,4
8-D	53,8	0,915	4,3	12,2	6,94	9,56
10-A	47	0,956				
10-B	47	0,957				
10-C	46,2	0,938	7,8	12,6	6,86	10,94
10-D	46,2	0,939	7,3	12,2	6,94	11,16
12-A	40,7	0,973				
12-B	40,8	0,975				
12-C	40,2	0,962	7,8	12,6	6,86	13,33
12-D	40,3	0,963	7,3	12,2	6,94	14,5

Table A 68: Scenario 18 (N-H-30-1) Costs and present worth.

N-H-30-1	O&M (M NOK)	CAPEX (M NOK)	Demand cost (NOK)	Energy cost (M NOK)	Energy purchased (kWh)	Energy sold (kWh)	Present worth (NOK)
3-A	4,01	0	595 860	3,41	4 460 212	0	0
3-B	4	0,22	574 607	3,41	4 464 916	0	29 190
3-C	3,77	2,03	591 577	3,17	4 137 028	4691	3 074 460
3-D	3,75	2,24	566 289	3,16	4 139 542	2255	3 207 390
6-A	4,1	0	609 853	3,49	4 460 212	0	0
6-B	4,09	0,22	588 105	3,49	4 464 916	0	-20 340
6-C	3,85	2,03	605 440	3,24	4 137 028	4691	1 954 960
6-D	3,84	2,24	579 555	3,24	4 139 542	2255	2 015 750
8-A	4,18	0	621 659	3,56	4 460 212	0	0
8-B	4,17	0,22	599 501	3,56	4 464 916	0	-48 130
8-C	3,93	2,03	617 138	3,3	4 137 028	4691	1 301 840

8-D	3,91	2,24	590 751	3,3	4 139 542	2255	1 321 750
10-A	4,26	0	633 476	3,63	4 460 212	0	0
10-B	4,25	0,22	610 914	3,63	4 464 916	0	-68 540
10-C	4	2,03	628 850	3,37	4 137 028	4691	810 570
10-D	3,99	2,24	601 960	3,36	4 139 542	2255	800 250
12-A	4,34	0	645 093	3,7	4 460 212	0	0
12-B	4,33	0,22	645 093	3,7	4 464 916	0	-84 040
12-C	4,08	2,03	640 366	3,43	4 137 028	4691	433 500
12-D	4,06	2,24	612 983	3,42	4 139 542	2255	400 190

SG110CX

Multi-MPPT String Inverter for 1000 Vdc System

HIGH YIELD

- 9 MPPTs with max. efficiency 98.7%
- Compatible with bifacial module
- Built-in PID recovery function

SMART O&M

- Touch free commissioning and remote firmware upgrade
- Smart IV Curve Diagnosis *
- Fuse free design with smart string current monitoring

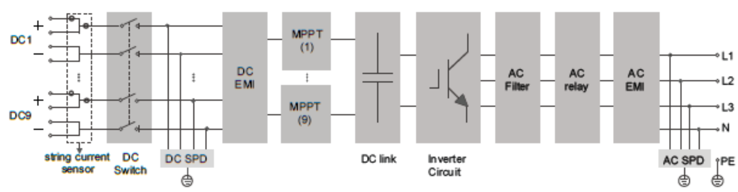
SAVED INVESTMENT

- Compatible with Al and Cu AC cables
- DC 2 in 1 connection enabled
- Q at night function

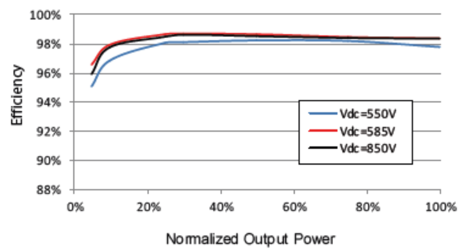
PROVEN SAFETY

- IP66 and C5 protection
- Type II SPD for both DC and AC
- Compliant with global safety and grid code

CIRCUIT DIAGRAM



EFFICIENCY CURVE



Type designation	SG110CX
Input (DC)	
Max. PV input voltage	1100 V **
Min. PV input voltage / Start-up input voltage	200 V / 250 V
Nominal PV input voltage	585 V
MPP voltage range	200 – 1000 V
No. of independent MPP inputs	9
No. of PV strings per MPPT	2
Max. PV input current	26 A * 9
Max. DC short-circuit current	40 A * 9
Output (AC)	
AC output power	110 kVA @ 45 ℃ / 100 kVA @ 50 ℃
Max. AC output current	158.8 A
Nominal AC voltage	3 / N / PE, 400 V
AC voltage range	320 – 460V
Nominal grid frequency / Grid frequency range	50 Hz / 45 – 55 Hz, 60 Hz / 55 – 65 Hz
Harmonic (THD)	< 3 % (at nominal power)
Power factor at nominal power / Adjustable power factor	> 0.99 / 0.8 leading – 0.8 lagging
Feed-in phases / AC connection	3 / 3-PE
Efficiency	
Max. efficiency	98.7 %
European efficiency	98.5 %
Protection and Function	
DC reverse polarity protection	Yes
AC short-circuit protection	Yes
Leakage current protection	Yes
Grid monitoring	Yes
Ground fault monitoring	Yes
DC switch	Yes
AC switch	No
PV string monitoring	Yes
Q at night function	Yes
PID recovery function	Yes
Arc fault circuit interrupter (AFCI)	Optional
Surge protection	DC Type II (optional: Type I + II) / AC Type II
General Data	
Dimensions (W*H*D)	1051*660*362.5 mm
Weight	89 kg
Topology	Transformerless
Degree of protection	IP66
Night power consumption	< 2 W
Operating ambient temperature range	-30 to 60 ℃ (> 50 ℃ derating)
Allowable relative humidity range	0 – 100 %
Cooling method	Smart forced air cooling
Max. operating altitude	4000 m (> 3000 m derating)
Display	LED, Bluetooth+APP
Communication	RS485 / Optional: WLAN, Ethernet
DC connection type	MC4 (Max. 6 mm^2)
AC connection type	OT / DT terminal (Max. 240 mm^2)
Compliance	IEC 62109, IEC 61727, IEC 62116, IEC 60068, IEC 61683, VDE-AR-N 4110:2018, VDE-AR-N 4120:2018, IEC 61000-6-3, EN 50549, AS/NZS 4777.2:2015, CEI 0-21, VDE 0126-1-1/A1 VFR 2014, UTE C15-712-1:2013, DEWA
Grid Support	Q at night function, LVRT, HVRT,active & reactive power control and power ramp rate control

*: Only compatible with Sungrow Logger, EyeM4 and iSolarCloud
**: The inverter enters the standby state when the input voltage ranges between 1,000V and 1,100V. If the maximum DC voltage in the system can exceed 1000V, the MC4 connectors included in the scope of delivery must not be used. In this case MC4 Evo2 connectors must be used.

Hi-MO 4

LR4-72HBD
440~460M

- Suitable for ground power plants and large C&I projects
- Advanced module technology delivers superior module efficiency
  - M6 Gallium-doped Wafer • 9-busbar Half-cut Cell
- Globally validated bifacial energy yield
- High module quality ensures long-term reliability

12 — 12-year Warranty for Materials and Processing

30 — 30-year Warranty for Extra Linear Power Output

Complete System and Product Certifications

IEC 61215, IEC 61730, UL 61730
ISO9001:2015: ISO Quality Management System
ISO14001: 2015: ISO Environment Management System
ISO45001: 2018: Occupational Health and Safety
IEC62941: Guideline for module design qualification and type approval

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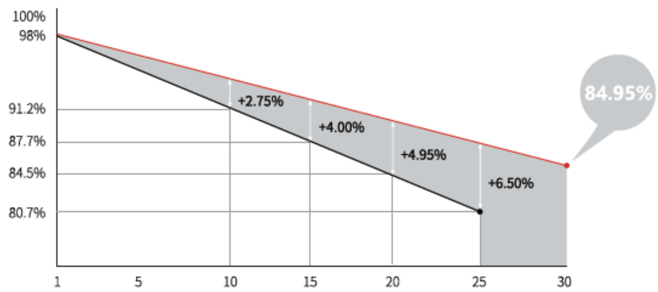
Hi-MO 4

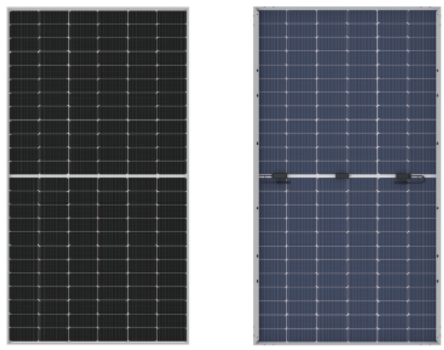
LR4-72HBD 440~460M

21.2%	0~3%	<2%	0.45%	HALF-CELL
MAX MODULE EFFICIENCY	POWER TOLERANCE	FIRST YEAR POWER DEGRADATION	YEAR 2-30 POWER DEGRADATION	Lower operating temperature

Additional Value

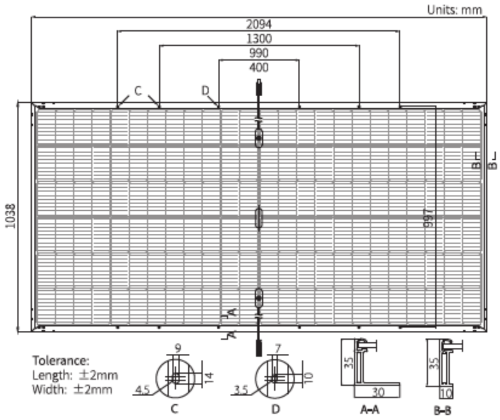
30-Year Power Warranty





Mechanical Parameters

Cell Orientation	144 (6×24)
Junction Box	IP68, three diodes
Output Cable	4mm², +400, -200mm/±1400mm length can be customized
Glass	Dual glass, 2.0+2.0mm heat strengthened glass
Frame	Anodized aluminum alloy frame
Weight	27.5kg
Dimension	2094×1038×35mm
Packaging	31pcs per pallet / 155pcs per 20' GP / 682pcs per 40' HC



Electrical Characteristics

STC : AM1.5 1000W/m² 25°C NOCT : AM1.5 800W/m² 20°C 1m/s Test uncertainty for Pmax: ±3%

Module Type	LR4-72HBD-440M		LR4-72HBD-445M		LR4-72HBD-450M		LR4-72HBD-455M		LR4-72HBD-460M	
Testing Condition	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT
Maximum Power (Pmax/W)	440	329.8	445	333.6	450	337.3	455	341.1	460	344.8
Open Circuit Voltage (Voc/V)	49.2	46.3	49.4	46.5	49.6	46.6	49.8	46.8	50.0	47.0
Short Circuit Current (Isc/A)	11.45	9.23	11.52	9.28	11.58	9.34	11.65	9.39	11.73	9.45
Voltage at Maximum Power (Vmp/V)	41.0	38.4	41.2	38.6	41.4	38.8	41.6	38.9	41.8	39.1
Current at Maximum Power (Imp/A)	10.73	8.60	10.80	8.65	10.87	8.70	10.93	8.76	11.01	8.82
Module Efficiency(%)	20.2		20.5		20.7		20.9		21.2	

Electrical characteristics with different rear side power gain (reference to 450W front)

Pmax /W	Voc/V	Isc /A	Vmp/V	Imp /A	Pmax gain
473	49.6	12.16	41.4	11.41	5%
495	49.6	12.74	41.4	11.95	10%
518	49.7	13.32	41.5	12.50	15%
540	49.7	13.90	41.5	13.04	20%
563	49.7	14.48	41.5	13.58	25%

Operating Parameters

Operational Temperature	-40°C ~ +85°C
Power Output Tolerance	0 ~ 3%
Voc and Isc Tolerance	±3%
Maximum System Voltage	DC1500V (IEC/UL)
Maximum Series Fuse Rating	25A
Nominal Operating Cell Temperature	45±2°C
Protection Class	Class II
Bifaciality	70±5%
Fire Rating	UL type 29 IEC Class C

Mechanical Loading

Front Side Maximum Static Loading	5400Pa
Rear Side Maximum Static Loading	2400Pa
Hailstone Test	25mm Hailstone at the speed of 23m/s

Temperature Ratings (STC)

Temperature Coefficient of Isc	+0.050%/°C
Temperature Coefficient of Voc	-0.265%/°C
Temperature Coefficient of Pmax	-0.340%/°C

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Web: www.longi.com

Hi-MO 4m

LR4-72HPH
430~460M

- Suitable for ground power plants and distributed projects
- Advanced module technology delivers superior module efficiency
  - M6 Gallium-doped Wafer • 9-busbar Half-cut Cell
- Excellent outdoor power generation performance
- High module quality ensures long-term reliability

12 — 12-year Warranty for Materials and Processing

25 — 25-year Warranty for Extra Linear Power Output

Complete System and Product Certifications

IEC 61215, IEC 61730, UL 61730
ISO 9001:2015: ISO Quality Management System
ISO 14001: 2015: ISO Environment Management System
TS62941: Guideline for module design qualification and type approval
ISO 45001: 2018: Occupational Health and Safety

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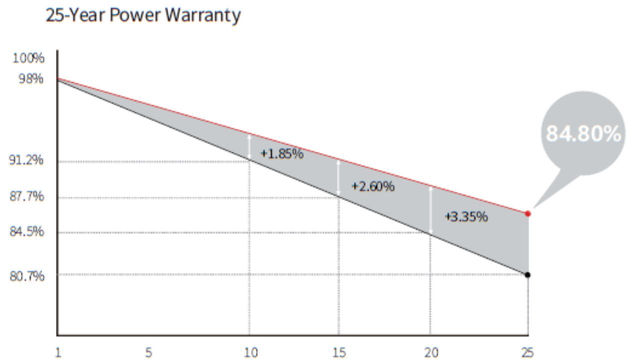
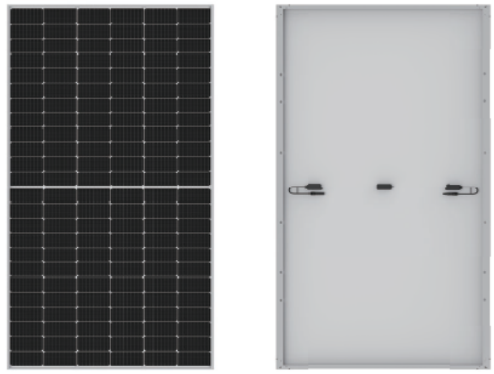
Hi-MO 4m

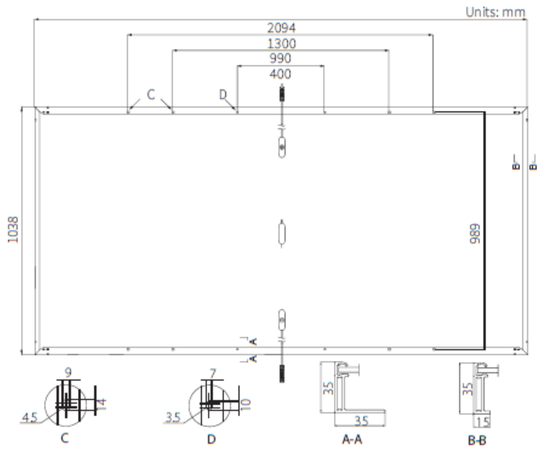
LR4-72HPH 430~460M

21.2%	0~+5W	<2%	0.55%	HALF-CELL
MAX MODULE EFFICIENCY	POWER TOLERANCE	FIRST YEAR POWER DEGRADATION	YEAR 2-25 POWER DEGRADATION	Lower operating temperature

Additional Value







Mechanical Parameters

Cell Orientation	144 (6×24)
Junction Box	IP68, three diodes
Output Cable	$4mm^2$, +400, -200mm/±1400mm length can be customized
Glass	Single glass, 3.2mm coated tempered glass
Frame	Anodized aluminum alloy frame
Weight	23.3kg
Dimension	2094×1038×35mm
Packaging	30pcs per pallet / 150pcs per 20' GP / 660pcs per 40' HC

Electrical Characteristics

STC : AM1.5 1000W/m² 25°C NOCT : AM1.5 800W/m² 20°C 1m/s Test uncertainty for Pmax: ±3%

Module Type	LR4-72HPH-430M		LR4-72HPH-435M		LR4-72HPH-440M		LR4-72HPH-445M		LR4-72HPH-450M		LR4-72HPH-455M		LR4-72HPH-460M	
Testing Condition	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT	STC	NOCT
Maximum Power (Pmax/W)	430	321.1	435	324.9	440	328.6	445	332.3	450	336.1	455	339.8	460	343.5
Open Circuit Voltage (Voc/V)	48.5	45.5	48.7	45.7	48.9	45.8	49.1	46.0	49.3	46.2	49.5	46.4	49.7	46.6
Short Circuit Current (Isc/A)	11.31	9.15	11.39	9.21	11.46	9.27	11.53	9.33	11.60	9.38	11.66	9.43	11.73	9.48
Voltage at Maximum Power (Vmp/V)	40.7	37.9	40.9	38.1	41.1	38.3	41.3	38.5	41.5	38.6	41.7	38.8	41.9	39.0
Current at Maximum Power (Imp/A)	10.57	8.47	10.64	8.53	10.71	8.59	10.78	8.64	10.85	8.70	10.92	8.75	10.98	8.80
Module Efficiency(%)	19.8		20.0		20.2		20.5		20.7		20.9		21.2	

Operating Parameters

Operational Temperature	-40°C ~ +85°C
Power Output Tolerance	0 ~ +5 W
Voc and Isc Tolerance	±3%
Maximum System Voltage	DC1500V (IEC/UL)
Maximum Series Fuse Rating	20A
Nominal Operating Cell Temperature	45±2°C
Protection Class	Class II
Fire Rating	UL type 1 or 2

Mechanical Loading

Front Side Maximum Static Loading	5400Pa
Rear Side Maximum Static Loading	2400Pa
Hailstone Test	25mm Hailstone at the speed of 23m/s

Temperature Ratings (STC)

Temperature Coefficient of Isc	+0.048%/°C
Temperature Coefficient of Voc	-0.270%/°C
Temperature Coefficient of Pmax	-0.350%/°C

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Appendix C Analysis figures and tables

C.1 Electricity price prognosis figures and tables

Table C 1: Predictions for spot prices and price variations by Statnett, as well as estimated multiplying factors.

	Yearly average hourly prices (øre/kWh)			Multiplying factor			Average price variation (øre/kWh)		
Year	**Low**	**Basis**	**High**	**Low**	**Basis**	**High**	**Daily**	**Weekly**	**Monthly**
2023	99.29	99.29	99.29	1.000	1.000	1.000	18.76	24.24	31.13
2024	61.59	77.84	100.09	0.620	0.784	1.008	17.24	22.61	29.01
2025	59.02	76.13	107.78	0.594	0.767	1.086	15.72	20.98	26.88
2026	47.05	67.58	90.68	0.474	0.681	0.913	14.20	19.35	24.76
2027	42.77	55.60	78.70	0.431	0.560	0.793	12.69	17.72	22.63
2028	47.05	60.74	82.12	0.474	0.612	0.827	11.16	16.09	20.50
2029	38.92	49.62	66.72	0.392	0.500	0.672	9.65	14.46	18.37
2030	30.80	38.49	51.33	0.310	0.388	0.517	8.13	12.83	16.25
2031	31.65	39.86	52.18	0.319	0.401	0.526	8.04	12.49	15.74
2032	32.51	41.23	53.04	0.327	0.415	0.534	7.96	12.15	15.23
2033	33.36	42.60	53.89	0.336	0.429	0.543	7.87	11.80	14.71
2034	34.22	43.97	54.75	0.345	0.443	0.551	7.78	11.46	14.20
2035	35.07	45.34	55.60	0.353	0.457	0.560	7.70	11.12	13.69
2036	33.02	43.46	53.72	0.333	0.438	0.541	7.36	10.78	13.26
2037	30.97	41.57	51.84	0.312	0.419	0.522	7.01	10.44	12.83
2038	28.91	39.69	49.96	0.291	0.400	0.503	6.67	10.09	12.40
2039	26.86	37.81	48.08	0.271	0.381	0.484	6.33	9.75	11.98
2040	24.81	35.93	46.19	0.250	0.362	0.465	5.99	9.41	11.55
2041	24.55	35.76	45.94	0.247	0.360	0.463	5.90	9.28	11.42
2042	24.29	35.59	45.68	0.245	0.358	0.460	5.82	9.15	11.29
2043	24.04	35.41	45.42	0.242	0.357	0.458	5.73	9.02	11.16
2044	23.78	35.24	45.17	0.240	0.355	0.455	5.65	8.90	11.04
2045	23.52	35.07	44.91	0.237	0.353	0.452	5.56	8.77	10.91
2046	23.27	34.90	44.65	0.234	0.352	0.450	5.47	8.64	10.78
2047	23.01	34.73	44.40	0.232	0.350	0.447	5.39	8.51	10.65
2048	22.75	34.56	44.14	0.229	0.348	0.445	5.30	8.38	10.52
2049	22.50	34.39	43.88	0.227	0.346	0.442	5.22	8.25	10.39
2050	22.24	34.22	43.63	0.224	0.345	0.439	5.13	8.13	10.27

** Orange color indicates interpolated values*

Table C 2: Predictions for spot prices by NVE, as well as estimated multiplying factors.

	Yearly average hourly prices (øre/kWh)			Multiplying factors		
Year	**Low**	**Basis**	**High**	**Low**	**Basis**	**High**
2023	99.29	99.29	99.29	1.000	1.000	1.000
2024	91.86	96.86	102.71	0.925	0.976	1.035
2025	84.43	94.43	106.14	0.850	0.951	1.069
2026	77.00	92.00	109.57	0.776	0.927	1.104
2027	69.57	89.57	113.00	0.701	0.902	1.138
2028	62.14	87.14	116.43	0.626	0.878	1.173
2029	54.71	84.71	119.86	0.551	0.853	1.207
2030	47.00	82.00	123.00	0.473	0.826	1.239
2031	44.00	77.00	115.00	0.443	0.776	1.158
2032	41.00	72.00	107.00	0.413	0.725	1.078
2033	38.00	67.00	99.00	0.383	0.675	0.997
2034	35.00	62.00	91.00	0.353	0.624	0.917
2035	32.00	57.00	83.00	0.322	0.574	0.836
2036	30.80	55.40	81.20	0.310	0.558	0.818
2037	29.60	53.80	79.40	0.298	0.542	0.800
2038	28.40	52.20	77.60	0.286	0.526	0.782
2039	27.20	50.60	75.80	0.274	0.510	0.763
2040	26.00	49.00	74.00	0.262	0.494	0.745

** Orange color indicates interpolated values*

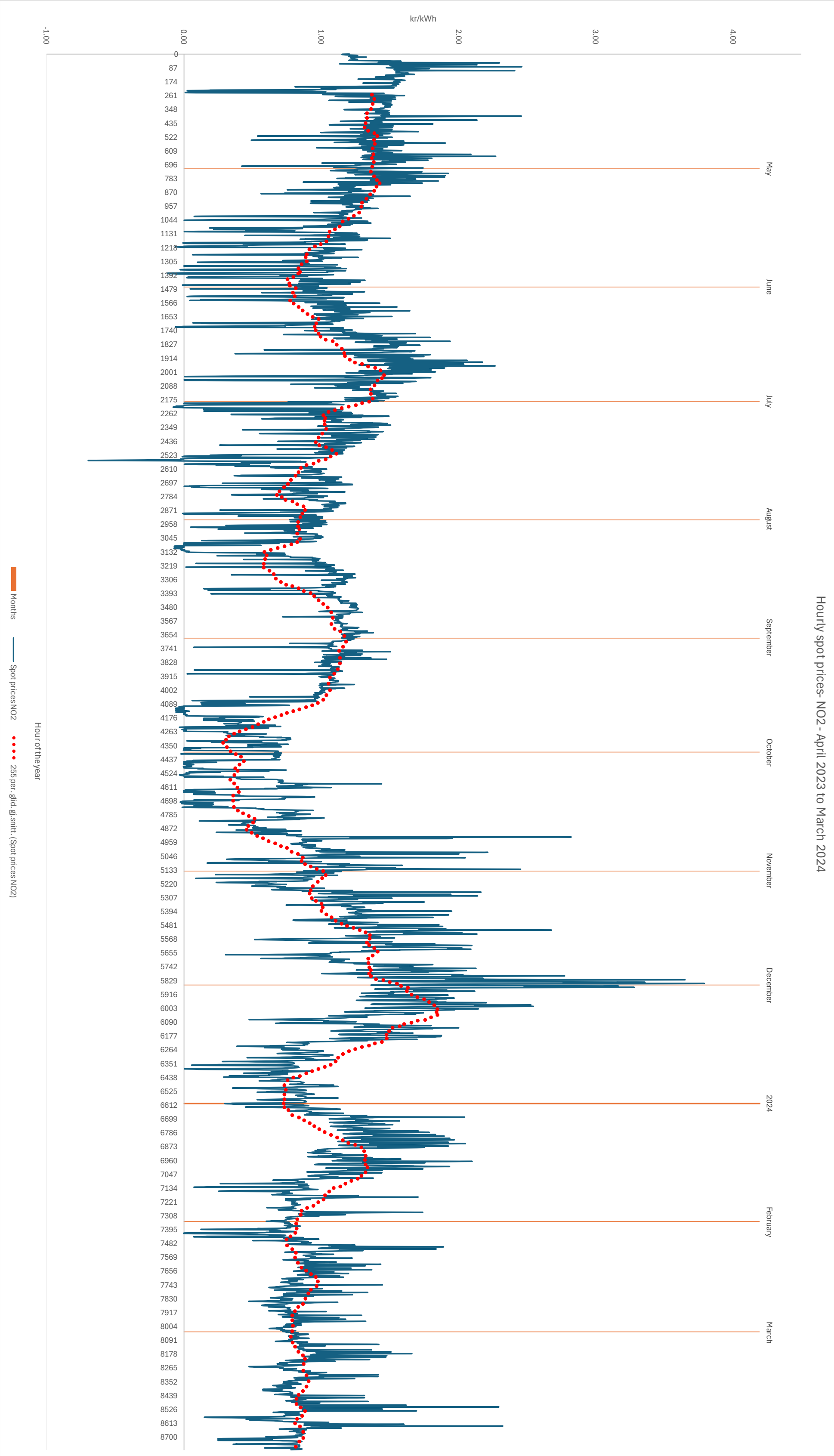

Figure C 1: Hourly spot prices for NO2 from April 2023 to March 2024. Red dots show the moving average with a sample size of 255.