HEAT SMART ORKNEY

AIB CAPSTONE PROJECT
KALUZA CASE STUDY

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Group L

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1. Executive Summary

Orkney experiences significant renewable energy curtailment when wind generation exceeds local demand. This report evaluates whether Kaluza can commercially exploit this opportunity through a residential demand response scheme using smart electric storage heaters. The scheme generates revenue through flexibility payments and wind farm service fees rather than household subscriptions, creating a commercially sustainable model funded by institutional revenues.

The analysis estimates annual curtailment of approximately 450,000 MWh, of which 268,146 MWh is considered technically addressable through demand response. However, residential demand response is unable to materially reduce system-wide curtailment. Even at the 32% Sc.A technical ceiling, the proposed scheme absorbs only 2,023 MWh per year, equivalent to 0.75% of the addressable pool. The primary finding is therefore that the commercial opportunity lies in monetising flexibility rather than eliminating curtailment.

Under the base-case assumptions, the scheme becomes commercially viable from 15% penetration and generates annual accounting profit of £151,112 at 30% penetration, with cumulative cash flow of £283,459 by Year 5. Sensitivity analysis identifies the SSEN flexibility payment as the dominant driver of profitability, while wind farm service fees and government subsidy have comparatively limited influence. The report therefore recommends a phased Sc.A rollout, conditional on securing a long-term flexibility agreement with SSEN, while treating expansion into the Sc.B segment as a future opportunity rather than an immediate priority.

2. Introduction

Orkney has one of the highest concentrations of renewable electricity generation in the United Kingdom. However, periods of high wind generation frequently exceed local demand, resulting in renewable electricity being curtailed rather than utilised. This creates both an operational challenge for the local energy system and a potential opportunity for demand-side flexibility.

Kaluza proposes to address this challenge through a residential flexibility scheme that uses demand response technology to shift household electricity consumption to periods of surplus wind generation. The proposed model would enrol households with electric storage heaters onto a demand response platform, automatically increasing electricity consumption during periods of curtailment in exchange for a participation incentive. By aggregating residential flexible demand, Kaluza would earn flexibility payments from the network operator and service fees from wind farm operators, creating a commercially sustainable model funded by institutional revenues rather than household subscriptions. We hypothesise that residential demand response can create a commercially viable revenue stream for Kaluza through network flexibility payments, despite absorbing only a small fraction of total curtailment.

3. Data and Assumptions

3.1 Data Overview

Two datasets underpin the analysis. The turbine telemetry dataset records output from a single Enercon E-44 900 kW turbine on Rousay Island at approximately one-minute intervals, spanning May 2015 to January 2018, with three columns: `Power_kw`, `Setpoint_kw`, and `Wind_ms`. Each observation is classified as spinning (setpoint = 900 kW), curtailed (0 < setpoint < 900 kW), or stopped (setpoint = 0 kW). This dataset drives all curtailment calculations.

The residential demand dataset contains 17,568 half-hourly observations covering 2017 and 2018 (`Timestamp`), recording mean household electricity demand (`Demand_mean_kw`) and a sample household size indicator (`N_households`). It is representative only, hence it is not matched temporally to the turbine telemetry, and is used exclusively for demand pattern analysis in **Section 6**. `N_households` is excluded from all downstream calculations.

3.2 Data Quality Assessment

The residential demand dataset is complete with consistent 30-minute spacing. A single 2018 observation was removed, leaving 17,520 records. An anomalous spike in `N_households` during September 2017 and October 2017 was treated as a data artefact. A three-standard-deviation outlier check flagged 21 observations above 0.489 kW per household; these corresponded to plausible winter evening peaks and were retained.

For the turbine telemetry, rows with any missing values were dropped, leaving a cleaned dataset spanning 2.63 years. Missing data is unevenly distributed: coverage is near-complete in winter but exceeds 33% in several months between April and November, meaning curtailment figures for those seasons are likely understated. The full coverage profile is in **Appendix D.6**.

3.3 Assumptions

The complete assumptions register with justifications and sources is provided in. **Appendix 0: Assumptions**.

4. Energy Curtailment Framework

4.1 Defining Curtailment

Wind curtailment refers to potential wind generation that is not ultimately produced due to network or operational constraints. In Orkney, curtailment occurs when available renewable generation exceeds the combined absorption capacity of local electricity demand and the 40 MW subsea export cable. The network operator therefore reduces turbine output to maintain network stability.

Within this analysis, curtailed energy is defined as the difference between potential generation under unconstrained conditions and realised turbine output observed in the telemetry data. This represents renewable energy that could have been generated but was not.

Demand response seeks to reduce this gap by increasing flexible electricity consumption during periods of network congestion, allowing a greater proportion of available wind generation to be absorbed locally.

4.2 Operating States

Four operating states determine realised turbine output. In wind-limited conditions, insufficient wind resource restricts generation and no curtailment occurs. In capacity-limited conditions, output reaches the turbine's rated capacity of 900 kW and cannot increase further regardless of wind speed. Because this limit is imposed by turbine design, it cannot be addressed through demand response.

Curtailment occurs in demand-limited conditions, where available generation exceeds the combined absorption capacity of local demand and the export cable. This is the dominant operating state in Orkney and the primary target for demand response intervention. In some periods, turbine capacity limits and network constraints may occur simultaneously. Detailed examples are provided in **Appendix A**.

4.3 Curtailment Modelling Framework

Curtailment is estimated using a simplified system boundary in which realised turbine output is treated as the volume of renewable generation successfully absorbed by the electricity system at each timestamp. The 40 MW export cable is treated as the underlying structural cause of curtailment rather than as a direct model input.

Curtailment is calculated as:

$$Curtailment \ = \ max(0, \ Potential\, Power \ - \ Power\_kw)$$

where `Potential Power` is estimated from the empirical power curve and `Power_kw` represents realised turbine output. `Setpoint_kw` is not included directly in the calculation and is instead used during power curve reconstruction to identify likely unconstrained operating periods.

The `max(0, …)` condition prevents negative curtailment values when realised output exceeds estimated potential generation due to power curve smoothing. In these cases, curtailment is recorded as zero.

Telemetry is recorded at one-minute intervals in kilowatts (kW). Each observation therefore represents 1/60 of a kWh before aggregation into MWh and GWh for fleet-scale reporting. The recoverable proportion of curtailed energy is examined in **Section 7**.

5. Power Curve Reconstruction

5.1 Conceptual Basis

Estimating wind curtailment requires a benchmark for the amount of electricity the turbine could potentially generate under unconstrained operating conditions. Because the telemetry dataset records realised turbine output rather than theoretical output, potential generation must be reconstructed empirically from the observed relationship between wind speed and power production.

This analysis reconstructs the power curve using telemetry from an Enercon E-44 900 kW turbine. Consistent with the published operating specification, the reconstructed curve applies a 2.5 m/s cut-in threshold, a rated-capacity plateau at 900 kW, and a storm-control taper between 28 and 34 m/s. The resulting interpolation function provides an estimate of potential generation at each observed wind speed and forms the benchmark used to estimate curtailed energy in **Section 7**. The full reconstruction methodology is provided in **Appendix B**.

5.2 Empirical Reconstruction

The power curve was reconstructed empirically from the turbine telemetry data using the subset of observations most likely to represent unconstrained turbine operation. Records were filtered using turbine setpoint and operating conditions to remove periods affected by curtailment or shutdown, while retaining observations across the full wind speed range. Potential generation was therefore estimated using the upper envelope of performance within narrow wind speed intervals rather than the full unconstrained sample. Full filtering criteria and sample construction are provided in **Appendix B.2**.

The filtered observations were grouped into 0.5 m/s wind speed bins and the P90 output within each bin was used as the base-case estimate of potential generation. P50 and P95 estimators were also reconstructed for sensitivity analysis. A cubic smoothing spline was then fitted through the binned P90 observations to produce a continuous interpolation function mapping wind speed to potential turbine output. Physical operating constraints from the published Enercon E-44 specification were subsequently imposed directly on the reconstructed curve, including a 2.5 m/s cut-in threshold, a rated-capacity plateau at 900 kW, and a storm-control taper between 28 and 34 m/s. The detailed reconstruction procedure is provided in **Appendix B.3** and **Appendix B.4**.

5.3 Validation

Figure 5.1 plots the fitted P50, P90, and P95 curves over the unconstrained scatter sample. The P90 base case forms a stable upper envelope over the bulk of observed output, with the expected non-linear rise through the operating region, a stable plateau at 900 kW, and a linear taper through the storm-control region. The P90 and P95 curves are nearly indistinguishable across the full wind speed range, indicating that the reconstructed upper envelope is not highly sensitive to the choice of quantile threshold.

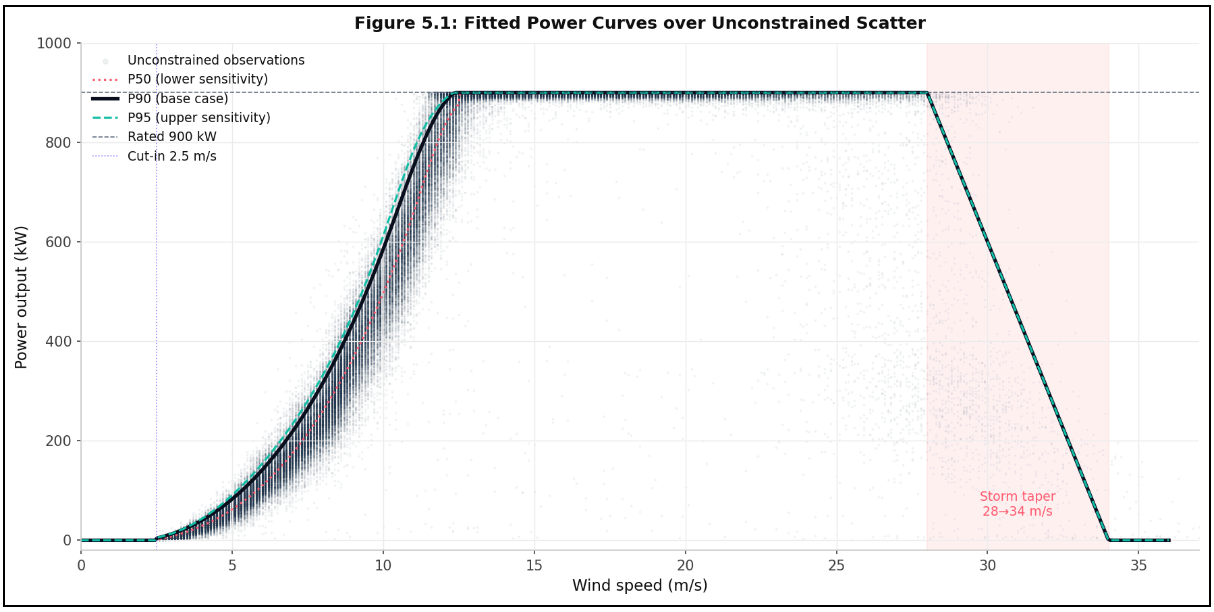

Figure 5.1: Reconstructed P50, P90, and P95 power curves over unconstrained turbine observations

Seasonal stability analysis further indicates that the relationship between wind speed and turbine output does not vary materially across winter, spring, summer, and autumn conditions, supporting the use of a single annual power curve across the full telemetry dataset. Full validation detail and sensitivity outputs are provided in **Appendix B.5**.

6. Residential Demand Patterns

The residential demand dataset was analysed to identify how household electricity demand varies across the day and across seasons. Consistent with the methodology established in **Section 4**, the actual demand proxy used in the curtailment calculations is `Power_kw` from the turbine dataset. Full data preparation and validation procedures are provided in **Appendix C.1**.

Figure 6.1 plots the average hourly residential demand profile for each meteorological season. All four seasons exhibit a broadly similar daily structure characterised by low overnight demand, a sharp morning increase, relatively stable daytime consumption, and a pronounced evening peak between approximately 17:00 and 18:00. Winter displays the highest demand profile throughout the day, peaking at 0.449 kW per household at 18:00, which is 58% above the summer peak of 0.285 kW at 17:00. In all seasons, minimum demand occurs during the early morning hours between approximately 03:00 and 04:00. Seasonal mean demand averages 0.260 kW per household in winter compared with 0.187 kW in summer, reflecting the additional heating load during colder months. Additional seasonal profile analysis and monthly demand variation are provided in **Appendix C.2** and **Appendix C.3**.

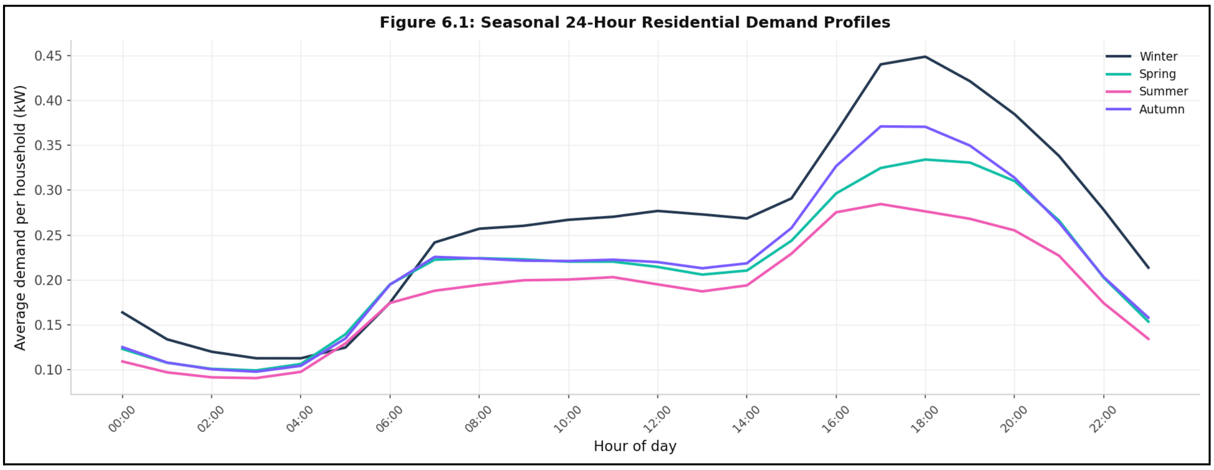

Figure 6.1: Seasonal 24-Hour Residential Demand Profiles

These demand patterns inform the demand-response scheduling strategies evaluated in **Section 8**.

7. Curtailment Analysis

The reconstructed curtailment model estimates annual curtailed energy of 450 GWh/yr across the representative 600-turbine Orkney fleet, equivalent to 23.1% of estimated potential generation. Of this total, 268 GWh/yr corresponds to the setpoint-driven component associated with network operator curtailment instructions, representing the demand-response-addressable pool. ***Figure 7.1*** shows that curtailment persists throughout the year rather than occurring only during isolated peak-wind periods. Export saturation occurs in 75.4% of observed hours, indicating that curtailment reflects a structural network constraint rather than an intermittent operational issue. Full calculation methodology and annual summary are provided in **Appendix D.1** and **Appendix D.2**.

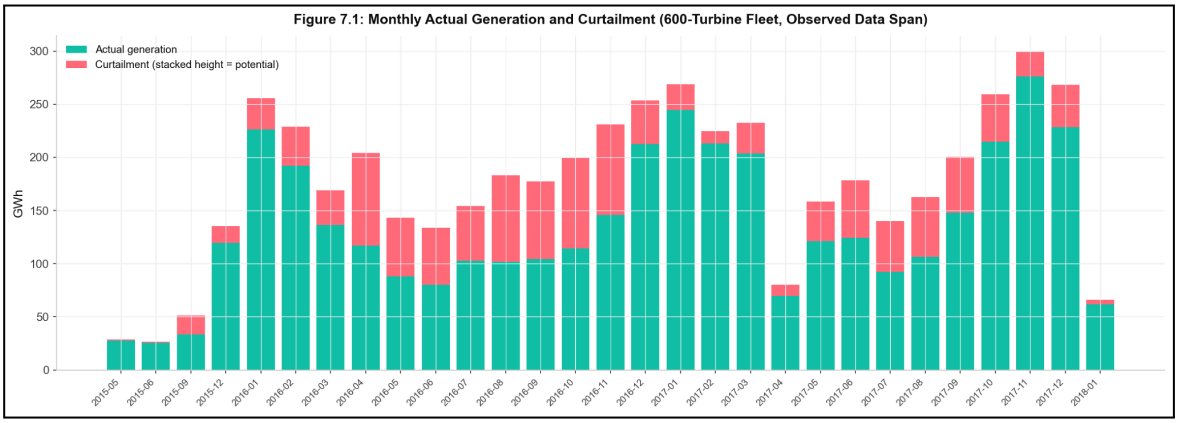

Figure 7.1: Monthly Actual Generation and Curtailment Across the Representative Orkney Wind Fleet

Seasonal curtailment patterns are summarised in **Appendix D.3**. Autumn records the largest annual curtailment volume at 145.3 GWh/yr, while winter records the lowest curtailment rate at 11.9% despite exhibiting the highest average wind speeds. This pattern is explained by the seasonal demand variation documented in **Section 6**: seasonal mean residential demand averages 0.260 kW per household in winter compared with 0.187 kW in summer (**Appendix C.3**), increasing the volume of generation the system can absorb before network constraints bind. Absolute curtailment figures for spring, summer, and autumn are likely understated due to missing data rates of 25% to 37% in those months; missing data assessment is provided in **Appendix D.6**.

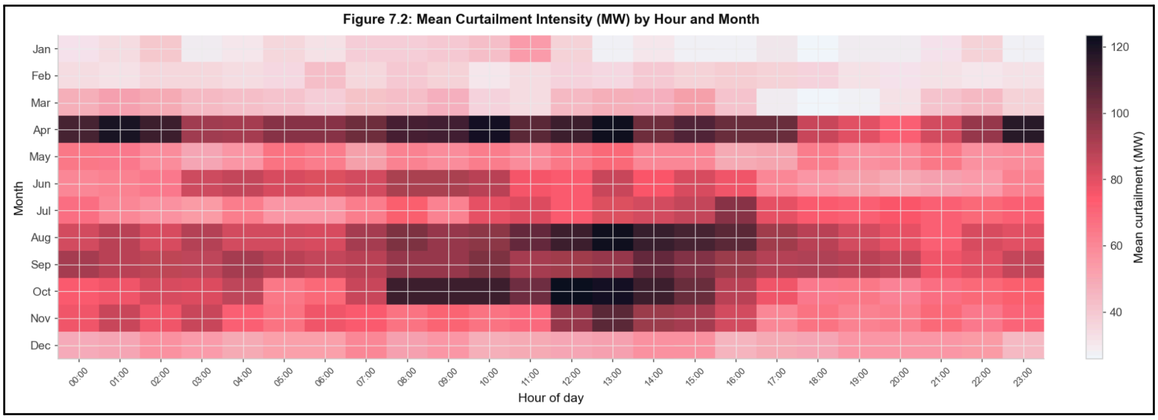

Figure 7.2: Mean Curtailment Intensity (MW) by Hour and Month

Figure 7.2 shows that curtailment is concentrated during the late morning and afternoon period rather than overnight. Mean curtailment peaks at 13:00 at 78.1 MW, with average daytime curtailment between 08:00 and 17:00 reaching 71.9 MW compared with 63.6 MW overnight. The strongest curtailment intensity occurs during late summer and autumn, particularly between August and October. April also exhibits elevated apparent curtailment intensity relative to the surrounding months due to missing data concentrated in that month; this is discussed in **Appendix D.4** and **Appendix D.6**. These temporal patterns directly inform the device-scheduling strategies which are evaluated in **Section 8**.

At 268 GWh/yr, the demand-response-addressable pool represents a significant commercial opportunity for Kaluza: at £50/MWh this corresponds to approximately £24.8 million of unrealised annual generation value, and at roughly 2.5 times total annual Orkney residential electricity demand, even modest DR penetration can absorb a meaningful fraction without saturating household capacity. The financial viability therefore depends on the value per MWh absorbed rather than the volume of curtailment eliminated, which is explored in **Section 9**. The curtailment estimates across fleet assumptions between 500 and 700 turbines and full robustness testing is provided in **Appendix D.5** and **Appendix D.7**.

8. Commercial Deployment Strategy

8.1 Solution Design

Kaluza's proposed demand response platform would shift or increase electrical load at enrolled households during periods of curtailment. The primary mechanism is demand shifting: Dimplex Quantum storage heaters pre-charge their ceramic thermal stores during curtailment periods, allowing renewable electricity to be absorbed when available and released later when households require heat or hot water. A secondary mechanism is demand increase, whereby improved heating and hot water availability may lead some households to increase consumption at the margin through higher comfort levels or additional hot water usage.

The Dimplex Quantum storage heater was selected because it decouples electricity consumption from heat delivery through embedded thermal storage. This is particularly suited to Orkney because residential demand peaks during the early evening (**Section 6**), while curtailment is concentrated during the daytime period (**Section 7**). Mean curtailment peaks at 13:00, and average curtailment between 08:00 and 17:00 reaches 71.9 MW compared with 63.6 MW overnight. Kaluza's activation window therefore targets daytime curtailment rather than the conventional Economy 7 overnight charging window, maximising the volume of curtailed energy absorbed. A single DR device can control heat supply to multiple storage heaters in a household.

8.2 Customer Segmentation

The proposed rollout prioritises two household segments differentiated by existing heating infrastructure and deployment requirements. Segment A (Sc.A) consists of households already using electric storage heating systems. Based on OREF EPC survey data from 2022, used as a proxy for the 2017/18 heating mix given the absence of contemporaneous data, this group represents approximately 3,323 households, equivalent to 32% of Orkney households. Because the required heating infrastructure already exists, deployment only requires installation of a retrofit control hub linked to the existing storage heater system at an estimated cost of approximately £125 per household. This substantially reduces installation complexity and behavioural friction, making Sc.A the primary deployment segment during the initial rollout phase.

Segment B (Sc.B) consists of households currently using oil- or coal-based heating systems, representing approximately 2,908 households or 28% of the Orkney housing stock. Deployment within this segment requires replacement with compatible electric thermal storage systems. Based on the assumptions established in **AppendixAssumptions**, this implies approximately two Dimplex Quantum heaters per household at an estimated total device cost of £1,200. Relative to Sc.A, this requires additional electrical installation work and appliance replacement in addition to device commissioning. The financial implications of each segment's deployment structure are evaluated in **Section 9**.

The proposed platform is supplier-agnostic and compatible with households regardless of electricity supplier. Although Sc.A and Sc.B represent the most operationally relevant segments for initial deployment, all 10,385 Orkney households remain potential future consumers within the broader flexibility model.

8.3 Proposed Business Model

The proposed business model monetises curtailed renewable generation through coordinated residential demand shifting. Kaluza operates as a domestic flexibility aggregator rather than a household energy supplier or device retailer, coordinating enrolled household demand during curtailment periods. The primary revenue stream derives from flexibility-market revenues benchmarked against SSEN/Piclo procurement prices for aggregated residential flexibility. The institutional framework underpinning these payments is summarised in **Appendix E.1**. A secondary revenue stream derives from generator service fees paid by wind farm operators on previously curtailed generation unlocked through demand shifting. Household participation incentives are funded through these institutional revenues, while the model also avoids direct household subscription charges in order to reduce adoption barriers. Government support reduces upfront deployment costs for eligible households but does not form the primary commercial foundation of the model. Overall viability depends on sufficient household enrolment, stakeholder coordination, and participation within the flexibility market.

Wind farm operators currently earn nothing on curtailed generation. The proposed generator service fee therefore creates incremental revenue from previously non-exported renewable generation with limited additional operational burden, making participation commercially rational.

Under the proposed model, household participation requires no upfront payment. Kaluza funds the cost of the control device and installation, recovering this through institutional revenues over the device lifetime. In return, enrolled households receive an annual participation incentive. For Sc.A households this proposition is straightforward, as existing storage heaters are already in place and only a retrofit hub is required. By contrast, Sc.B households require full appliance replacement, making the financial case less certain. In these cases participation may depend more heavily on grant-funded installation, improved access to controllable electric heating, and alignment with fuel-poverty and decarbonisation objectives. The extent to which these household propositions remain financially and operationally feasible is evaluated in **Sections 9** and **10**.

Government stakeholders benefit from alignment with existing fuel-poverty and decarbonisation objectives. Orkney's fuel poverty rate reached 58%, and existing support frameworks including ECO2t and Warmer Homes Scotland already target this household segment. The proposed scheme therefore aligns with existing policy priorities while using established grant infrastructure to reduce deployment friction. Fuel poverty acts as a policy enabler that improves feasibility and unlocks support mechanisms rather than as a commercial driver in its own right. Further background on these support mechanisms is provided in **Appendix E.2**.

For SSEN, aggregated residential flexibility provides a potential mechanism for reducing network constraint pressure without immediate grid reinforcement investment, representing a lower-cost alternative to cable upgrades for managing the 40 MW export constraint. For Kaluza, the model is designed to generate institutional flexibility revenues at relatively modest Sc.A penetration levels, as evaluated in **Sections 9** and **10**.

9. Financial Analysis

9.1 Cost Structure

The deployment model contains two distinct cost layers: upfront capex at installation and recurring annual operating expenditure. Deployment costs differ materially between segments. Sc.A households require only a retrofit smart-control hub connected to an existing storage heater at a total capex of approximately £225 per household, making deployment relatively low-cost and operationally scalable. By contrast, Sc.B households require full replacement with two Dimplex Quantum storage heaters at a total capex of approximately £1,450 per household, creating a substantially larger capital requirement.

Grant support materially reduces Kaluza's effective capex exposure. Using Orkney's fuel poverty rate of 58%, the majority of households are assumed eligible for Warmer Homes Scotland funding covering full device and installation costs. Remaining non-eligible capex totals approximately £314,100 for Sc.A deployment and £1.77 million for Sc.B deployment.

Annual Kaluza operating expenditure is estimated at approximately £79 per enrolled household alongside fixed annual overheads of approximately £85,100 per year. Overall, the cost structure indicates that Sc.A deployment is commercially scalable under moderate penetration levels, whereas Sc.B deployment remains substantially more dependent on grant support and wider policy objectives. Full cost assumptions, sourcing, and modelling inputs are provided in **Appendix F.1**.

9.2 Revenue Streams

The proposed business model generates revenue through institutional flexibility payments and generator service fees associated with previously curtailed renewable generation. Household participation incentives are funded through these institutional revenues rather than through direct household subscription charges.

The primary revenue stream derives from SSEN-style flexibility-market payments for aggregated residential demand shifting during curtailment periods. A base-case flexibility value of £250/MWh is adopted using early constrained-market-zone procurement benchmarks from 2017/18 (TED notice 292933-2017; SSEN, 2016), while a mature-market upside benchmark of £300/MWh is also considered using later SSEN/Piclo procurement outcomes reported by The Energyst (2019). The base-case assumption therefore applies an approximate 17% discount relative to the mature-market benchmark in order to reflect the earlier-stage nature of residential flexibility markets during 2017/18. These values are treated as benchmark proxies rather than guaranteed contract prices.

A secondary revenue stream derives from wind farmer service fees charged on previously curtailed renewable generation successfully unlocked through demand shifting. A base-case fee of £25/MWh is adopted as an internal modelling assumption. ***Figure 9.1*** demonstrates that even after payment of the wind farmer service fee, wind farm operators retain positive value from generation that would otherwise earn £0/MWh under curtailment conditions.

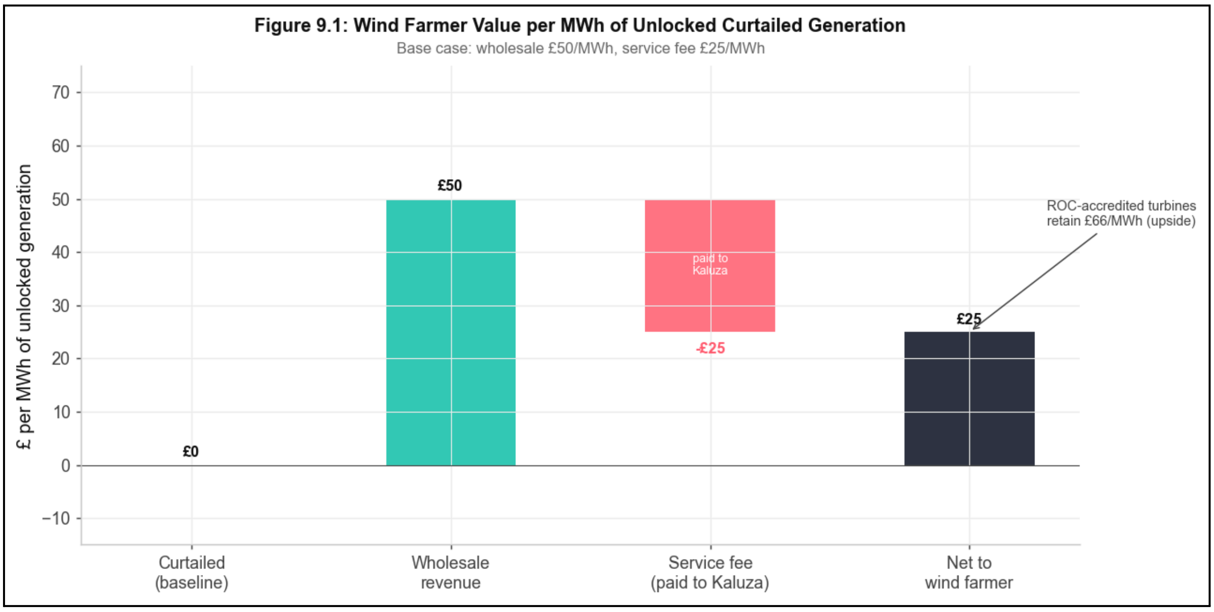

Figure 9.1: Wind Farmer Value Retained per MWh of Unlocked Curtailed Generation

Under the conservative wholesale-only base case, wind farmers retain approximately £25/MWh of previously unrealised generation value after payment to Kaluza, with higher retained values possible for turbines accredited under the Renewables Obligation scheme. Because curtailed generation currently earns £0/MWh, the service fee therefore creates incremental revenue on otherwise non-exported generation with limited additional operational burden.

Household participation incentives are modelled at £80 per household per year as the base case, funded through institutional flexibility revenues and split between Kaluza and government support as detailed in Appendix F.1. Full revenue assumptions and sourcing are provided in Appendix F.2.

9.3 Household Economics

Household economics differ materially between the two deployment segments. ***Figure 9.2*** compares annual household energy expenditure before and after participation in the proposed Kaluza scheme under 2017/18 energy prices, assuming no upfront device cost to the household.

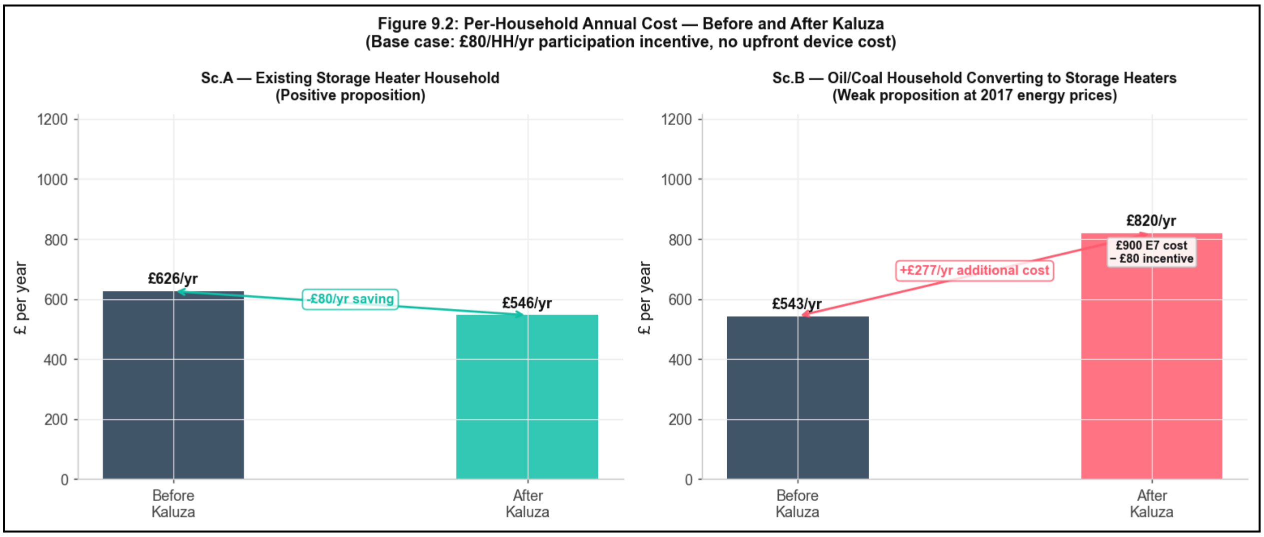

Figure 9.2: Annual Household Energy Cost Before and After Kaluza Participation

For Sc.A households, which already possess electric storage heaters, the financial proposition is relatively straightforward. Current annual electricity expenditure is estimated at approximately £626 per year based on Economy 7 consumption patterns and derived from the Ofgem prepayment price cap for North Scotland (April-September 2018) and the Ofgem Typical Domestic Consumption Values decision (August 2017). Under the proposed scheme, households incur no upfront device cost and receive a modelled participation incentive of £80 per year. Because the intervention primarily involves retrofitting a smart-control hub onto existing heating infrastructure, the household's underlying tariff structure remains unchanged while curtailment-period scheduling creates the potential for modest additional bill savings. The resulting proposition is therefore financially positive under the base-case assumptions.

The financial proposition for Sc.B households is substantially weaker. Current oil-heating expenditure is estimated at approximately £543 per year, while conversion to Economy 7 storage heating increases annual electricity expenditure to approximately £900 per year. After inclusion of the £80 participation incentive, the net household position remains approximately -£277 per year relative to the oil-heating baseline. At 2017/18 energy prices, oil heating therefore remains materially cheaper per kWh than Economy 7 electricity, meaning Sc.B households are financially worse off after conversion at any modelled incentive level.

Consequently, the Sc.B proposition cannot be justified through direct household cost savings alone. Instead, deployment depends more heavily on grant-funded installation, improved heating reliability and control, and the wider decarbonisation and fuel-poverty objectives outlined in **Section 8**. Full household-economics assumptions and calculations are provided in **Appendix F.3**.

Given these findings, the analysis presented in **Section 10** focuses on the Sc.A rollout as the base case. Although Sc.B households provide additional flexible demand potential, their adoption remains contingent on grant support, tariff innovation, or changes in relative energy prices and is therefore considered a future extension rather than part of the core deployment strategy.

10. Demand Response Potential and Commercial Viability

10.1 Curtailment Reduction by Penetration Level

Table 10.1 presents the curtailment absorption results generated based on the methodology outlined in Appendix G.1 for six Sc.A household penetration scenarios, ranging from 10% participation to the 32% technical ceiling identified in Section 8.2. Under the base-case assumptions, annual absorption increases from 646 MWh at 10% penetration to 2,023 MWh at the technical ceiling, equivalent to 0.24% and 0.75% of the DR-addressable curtailment pool respectively. Absorption increases approximately linearly with penetration because available daytime curtailment substantially exceeds the flexible demand capacity provided by enrolled households across all scenarios.

Sc.A Penetration	Enrolled Households	Flexible Capacity (MW)	Base Case Absorption (MWh/yr)	Sensitivity Absorption (MWh/yr)	Share of DR-Addressable Curtailment
10%	1,039	1.6	646	880	0.24%
15%	1,558	2.4	963	1,313	0.36%
20%	2,077	3.2	1,277	1,743	0.48%
25%	2,596	4	1,589	2,169	0.59%
30%	3,116	4.8	1,900	2,594	0.71%
32% ceiling	3,323	5.12	2,023	2,762	0.75%

Table 10.1: Demand Response Curtailment Absorption under Alternative Sc.A Penetration Scenarios

The proposed demand response mechanism operates through demand shifting. Kaluza pre-charges storage heaters during the 08:00–17:00 daytime curtailment window identified in Section 7, where mean curtailment peaks at 13:00 and reaches 78.1 MW. The stored thermal energy is subsequently released during the evening residential demand peak identified in Section 6, which occurs between 17:00 and 18:00. The simulation captures demand shifting only and does not account for potential demand increase effects, whereby fuel-poor households may partially convert heating improvements into higher thermal comfort rather than purely reduced expenditure (Milne and Boardman, 2000; Chitnis and Sorrell, 2015). Actual curtailment absorption may therefore be modestly higher than the modelled estimates.

Despite the large volume of available curtailment, absorption remains constrained by household thermal storage capacity rather than curtailment availability. Each household is limited by the 10 kWh/day thermal storage assumption, meaning the binding constraint is the amount of energy that can be stored rather than the amount of curtailed generation available. Even at the 32% Sc.A technical ceiling, demand response absorbs only 0.75% of the DR-addressable curtailment pool. Correspondingly, absorbing 1% of the DR-addressable pool would require household participation beyond the Sc.A technical ceiling, indicating that larger reductions would require expansion into Sc.B households or alternative sources of flexible demand. Consequently, demand response does not eliminate curtailment. Instead, the commercial case depends on the value captured per MWh absorbed rather than the volume of curtailment removed.

10.2 Commercial Viability

The commercial viability assessment uses the curtailment absorption estimates presented in ***Table 10.1*** and the financial assumptions established in **Section 9**. Full accounting profit and cash flow outputs are provided in **Appendix G.2**. Under the base-case assumptions of an SSEN flexibility payment of £250/MWh, a wind farmer service fee of £25/MWh and no additional government subsidy, annual revenue, costs and accounting profit at each penetration level are shown in ***Figure 10.1***. The scheme is not viable at 10% penetration, generating an annual loss of £2,901, but reaches its first accounting break-even point at 15% penetration, equivalent to 1,558 enrolled households and £36,590 of annual profit. Annual profit subsequently increases to £75,257 at 20% penetration, £113,374 at 25% penetration and £151,112 at 30% penetration.

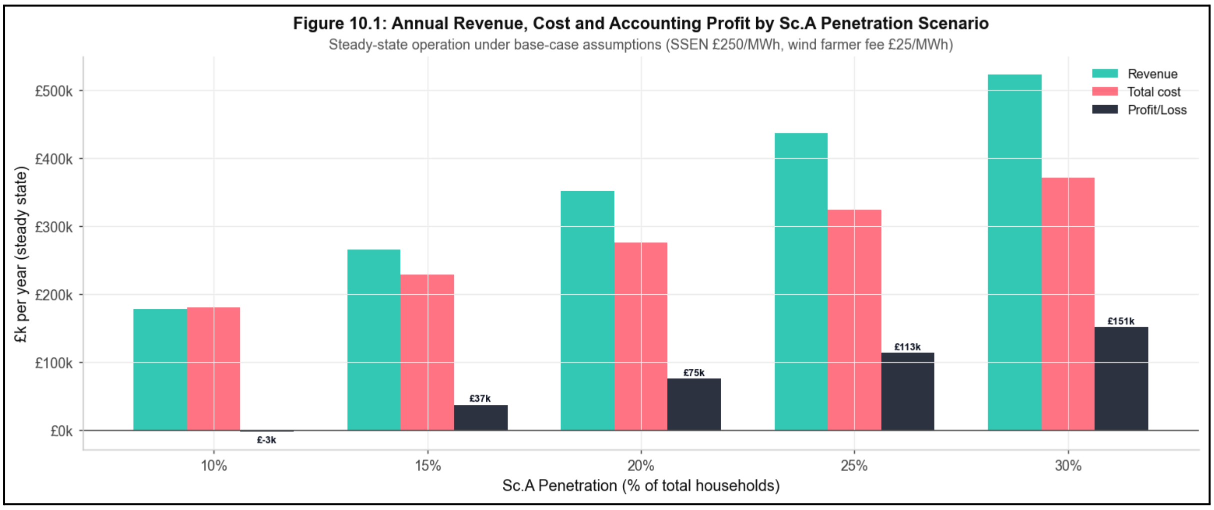

Figure 10.1: Annual Revenue, Cost and Accounting Profit by Sc.A Penetration Scenario

However, annual accounting profitability does not imply immediate cash-flow recovery. ***Figure 10.2*** shows that cumulative cash flow remains negative during the rollout phase because device and installation costs are incurred upfront, whereas revenues accrue gradually as the enrolled base expands. Under the 30% penetration scenario, cumulative cash flow falls to a trough of £-145,804 by the end of 2019 before recovering as the scheme reaches full deployment. Annual cash flow turns positive in 2020 as the scheme reaches full deployment, and cumulative cash flow turns positive during 2021. By Year 5, cumulative cash flow reaches £283,459. The corresponding net present value, using a 10% discount rate, is £156,819.

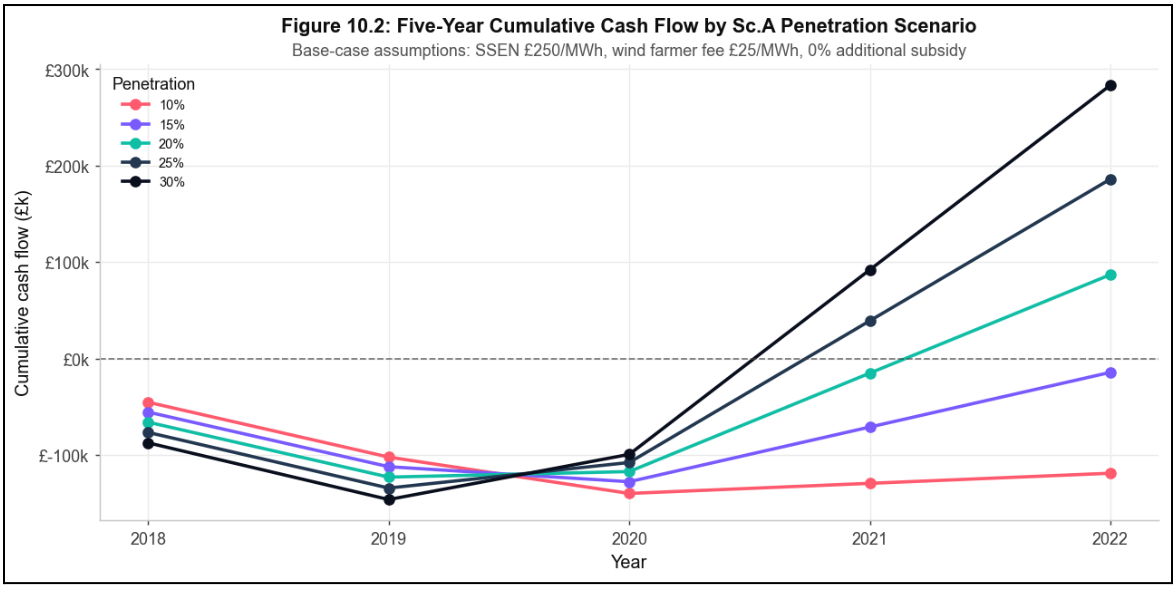

Figure 10.2: Five-Year Cumulative Cash Flow by Sc.A Penetration Scenario

The five-year analysis indicates that 10% and 15% penetration scenarios do not fully recover rollout costs within the five-year projection period, whereas penetration levels of 20% and above generate positive cumulative cash flow by Year 5. Commercial viability also remains relatively robust to changes in flexibility prices. The minimum SSEN payment required for annual profitability falls from £255/MWh at 10% penetration to £175/MWh at 30% penetration. Additional government subsidy improves project economics and lowers the penetration required for break-even, but is not necessary for viability at moderate participation levels. These findings inform the phased rollout strategy discussed in Section 13.

10.3 Sensitivity Analysis

The sensitivity analysis evaluates how changes in key commercial assumptions affect profitability. Full sensitivity outputs are provided in Appendix G.3. ***Figure 10.3*** summarises the impact of each variable on annual accounting profit at the 30% penetration scenario, where the base-case profit is £151,112.

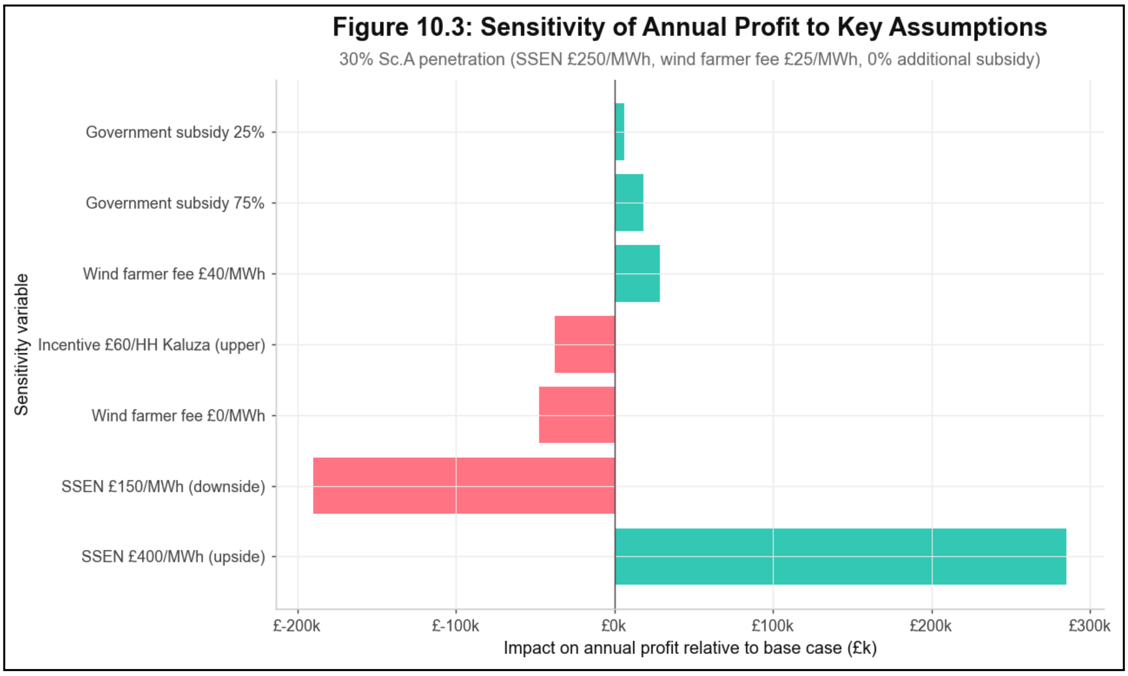

Figure 10.3: Sensitivity of Annual Profit to Key Assumptions

The results show that the SSEN flexibility payment is by far the most influential variable. Increasing the payment rate from the base-case assumption of £250/MWh to £400/MWh increases annual profit by £285,000, while reducing the rate to £150/MWh decreases annual profit by £190,000. These impacts are between four and six times larger than those associated with any other sensitivity tested, indicating that flexibility contract pricing is the primary driver of commercial viability.

In contrast, the model is comparatively less sensitive to wind farmer fees, government subsidy support and household incentive payments. At 30% penetration, annual profit remains positive at £103,612 even if no wind farmer fee is received, while increasing the fee to £40/MWh raises annual profit by £28,500. Similarly, government subsidy improves profitability and accelerates payback, but has a relatively modest impact on annual profit compared with flexibility revenues. The model also remains profitable when the Kaluza-funded household incentive is increased from £48 to £60 per household per year, reducing annual profit from £151,112 to £113,720.

Importantly, the commercial case does not depend on either government subsidy or wind farmer fee revenue. At 15% penetration, the scheme remains profitable with no wind farmer fee, generating an annual profit of £12,516. Furthermore, the minimum SSEN payment required for profitability at 30% penetration is £175/MWh, equivalent to £75/MWh below the £250/MWh base-case benchmark. Securing a flexibility contract close to this benchmark therefore represents the single most important commercial condition for viability.

11. Benefits to Stakeholders

The proposed demand response scheme generates benefits across multiple stakeholder groups. For Kaluza, the model becomes commercially viable from 15% Sc.A penetration under the base-case assumptions and generates annual profit of £151,112 at 30% penetration, with positive cumulative cash flow of £283,459 by Year 5. For wind farm operators, the scheme creates value from electricity that would otherwise be curtailed, while retaining wholesale revenue and receiving a £25/MWh service fee under the base-case arrangement.

Participating households benefit from zero upfront device costs, an £80 annual participation incentive, and potential bill savings through the use of low-cost curtailed electricity. Improved heating control may also enhance thermal comfort and energy affordability, particularly for fuel-poor households. For SSEN, aggregated residential flexibility provides a lower-cost mechanism for managing the 40 MW export constraint and reducing network pressure without immediate reinforcement of the existing export connection.

The scheme also delivers wider environmental benefits by converting curtailed renewable electricity into useful heat rather than allowing it to be wasted. Greater utilisation of locally generated wind power improves overall system efficiency and supports wider decarbonisation objectives. Any future expansion into Sc.B households would provide additional environmental benefits through the displacement of oil-based heating with renewable electricity.

12. Limitations

The findings presented in this report should be interpreted in light of several data, modelling and market-related limitations.

Data constraints. The curtailment model is built on telemetry from a single turbine scaled to a 600-turbine fleet, assuming uniform capacity and operating behaviour across all units. Missing observations were removed rather than imputed. Because curtailment is more likely during periods of high generation, annual curtailment may be understated and should be interpreted as a conservative estimate. The residential demand dataset is a representative sample used only to establish temporal consumption patterns and is not merged with curtailment data for any quantitative calculation.

Internal modelling assumptions. The analysis applies an Orkney-specific uplift to standard Ofgem consumption values to reflect the colder local climate. The 10 kWh/day thermal storage cap per household varies with ambient temperature, occupancy and existing store heat levels, and sensitivity analysis is provided in **Section 10.3**. Sc.B economics are sensitive to installation and appliance replacement costs, which vary across households and may be higher in remote locations such as Orkney. The demand response simulation assumes successful device activation whenever curtailment occurs and does not model communication failures, equipment downtime or participant attrition. Actual absorption volumes may therefore be lower than modelled.

Market assumptions. The OREF EPC 2022 data is used as a proxy for the 2017/18 heating mix, and housing stock composition may have changed materially in the intervening period. The £250/MWh SSEN flexibility payment is based on historical procurement benchmarks rather than a confirmed contract price. Commercial viability therefore remains dependent on future flexibility market conditions. The financial model uses static 2017/18 energy prices and does not forecast future price movements. Consequently, the Sc.B recommendation in **Section 13** remains conditional on relative fuel price developments.

The limitations identified above represent the most material sources of uncertainty in the analysis. A full register of all assumptions made throughout this report, together with their sources and associated limitations, is provided in **Appendix 0**.

13. Recommendations

On the basis of the analysis presented in this report, Kaluza should proceed with a phased Sc.A residential demand response rollout in Orkney. **Sections 6** and **7** identified 268,146 MWh/yr of DR-addressable curtailed generation and a clear temporal mismatch between daytime curtailment and evening residential demand. Storage heaters are well suited to this context because thermal energy can be stored during the daytime curtailment window and released during the evening demand peak between 17:00 and 18:00, decoupling electricity consumption from heat delivery. Although the scheme absorbs less than 1% of the DR-addressable pool, commercial viability depends on flexibility revenues rather than curtailment reduction. The opportunity therefore lies in monetising flexibility rather than eliminating curtailment.

However, deployment should be conditional on securing a long-term flexibility agreement with SSEN. The sensitivity analysis in **Section 10.3** demonstrates that the SSEN flexibility payment is the dominant driver of commercial viability, with impacts four to six times larger than any other variable tested. At 30% penetration, the model remains profitable at flexibility payments as low as £175/MWh, providing a £75/MWh buffer relative to the £250/MWh base-case benchmark. Securing a flexibility contract close to this benchmark should therefore be treated as the primary commercial objective before large-scale deployment. The recommendation is further supported by the existence of an established procurement pathway. SSEN's Constraint Managed Zone framework and the Piclo flexibility marketplace were already active during the analysis period, reducing implementation risk relative to a completely new commercial arrangement (**Appendix E.1**). From SSEN's perspective, aggregated residential flexibility provides a lower-cost mechanism for managing the 40 MW export constraint than network reinforcement, creating a clear incentive to procure flexibility services from aggregators such as Kaluza.

The rollout should follow the phased schedule established in the five-year financial model. Year 1 should focus on enrolling approximately 935 households, equivalent to 30% of the 30% penetration target, operating as a commercial pilot to validate dispatch performance, device utilisation, household participation and realised flexibility volumes. Household acquisition should be delivered through Community Energy Scotland, local community development trusts and existing home energy support programmes. Marketing should emphasise zero upfront costs, the £80 annual participation incentive, improved heating comfort and the use of locally generated renewable electricity. Kaluza should also coordinate Warmer Homes Scotland grant applications on behalf of eligible households to reduce administrative barriers to participation. Subject to successful pilot outcomes, enrolment should expand to approximately 70% of the target in Year 2 before reaching full deployment in Year 3. This approach aligns with the cash flow profile identified in **Section 10** and reduces early-stage commercial risk.

Expansion into the Sc.B segment should not form part of the initial deployment strategy. At 2017 energy prices, oil heating remains cheaper than Economy 7 electricity and the household proposition is not financially attractive without either a discounted curtailed electricity tariff or substantial grant support. Sc.B deployment should therefore be treated as a future option rather than an immediate objective. Kaluza should revisit the segment if relative fuel prices change, if a dedicated curtailed electricity tariff becomes available, or if flexibility market revenues increase sufficiently to support higher household incentives.

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AI Use Statement: Generative AI tools (OpenAI ChatGPT and Anthropic Claude) were used to support drafting, editing, proofreading and idea generation during the preparation of this report. All analysis, modelling, calculations, interpretations and conclusions were undertaken and verified by the authors.

15. Appendices

This appendix contains the narrative, methodology, assumptions, figures and tables supporting the analytical sections of this report. The accompanying Jupyter notebook maps directly to these appendix sections and contains the underlying code used to produce the reported outputs. The notebook is provided solely for reproducibility; all results, findings and conclusions are documented within this report.

Appendix 0: Assumptions Register Log

No.	Assumption	Source	Limitation
	Supply and Curtailment		
A1	600 turbines representing the Orkney fleet	Scottish Energy News Feb 2016 ('more than 660'); OREF Wind page ('over 700'); Energy Brief slide 5 ('more than 500')	Published sources cite 500–700+ turbines depending on year and definition. The 600-turbine figure is a central estimate that materially affects absolute curtailment volume.
A2	900 kW rated capacity per turbine (Enercon E-44)	Wind Turbine Models - Enercon E-44	Scaling assumes all fleet turbines are identical 900 kW units. In practice the Orkney fleet includes turbines of varying age, manufacturer and capacity.
A3	40 MW export cable constraint	Project FAQ / Energy Brief	No limitation. The 40 MW constraint is an established physical fact confirmed by multiple sources.
A4	Single turbine telemetry scaled to fleet level	Energy Brief	Scaling assumes uniform curtailment exposure across all units. Turbines at different locations and connection points experience different constraint patterns.
	Demand Response Simulation		
A5	70% DR availability factor	Internal modelling	No published benchmark identified. If actual availability is lower due to household absence, equipment failure or opt-out, absorbed MWh will be proportionally lower.
A6	10 kWh/day thermal cap per Sc.A household (base)	Project brief	Varies with ambient temperature, occupancy and existing heat store levels. Conservative central

			estimate. Sensitivity at 15 kWh/day provided in Section 10.3.
A7	2.2 kW device input rating per Sc.A household	Dimplex Quantum RF spec	No limitation. Directly stated in the Dimplex Quantum RF specification.
	Market and Segmentation		
A8	10,385 total Orkney households	Project FAQ	No limitation. Sourced directly from the project FAQ.
A9	3,323 Sc.A eligible households (32%)	OREF EPC survey 2022 - used as 2017/18 proxy	The 2022 EPC survey is used as a proxy for 2017/18. The heating mix may have changed materially due to fuel poverty programmes and heat pump adoption.
A10	2,908 Sc.B eligible households (28%)	OREF EPC survey 2022 - used as 2017/18 proxy	Same limitation as A9.
A11	58% fuel poverty rate	Orkney Sustainable Energy Strategy 2016	Fuel poverty rate does not map directly to grant eligibility. Actual eligibility depends on income thresholds and specific scheme criteria.
	Financial Model		
A12	SSEN flexibility payment - £250/MWh base case	TED notice 292933-2017; SSEN CMZ launch 2016	Benchmark proxy derived from published procurement data, not a contracted tariff. The actual rate negotiated with SSEN may differ.
A13	SSEN flexibility payment - £300/MWh upside	The Energyst, March 2019	Based on a 2019 market report. May not reflect the rate achievable in the 2017/18 early-stage CMZ market.
A14	Wind farmer service fee - £25/MWh	Internal modelling	Internally modelled. Wind farmers may negotiate a different rate or decline participation if net benefit after the fee is insufficient.
A15	Sc.A device cost - £100/HH	Project FAQ; Energy Brief 2026	No limitation. Sourced from the project FAQ and Energy Brief.
A16	Sc.A installation - £125/HH base	Refurbb guide, 2017-adjusted	Adjusted downward for 2017/18 labour market conditions. Actual costs in Orkney may be higher due

			to remote geography and limited contractor availability.
A17	Sc.B device cost - £1,200/HH (2× Dimplex Quantum)	Energy Brief 2026; HeaterShop 2017	HeaterShop pricing used as a proxy for 2017 device costs. Actual prices may differ.
A18	Sc.B installation - £250/HH	Internal modelling - no pre-2017 primary source identified	No pre-2017 primary source identified. Likely conservative for Orkney given ferry logistics and limited local contractors.
A19	Household participation incentive - £80/HH/yr total	BBC News on Octopus DFS (2022); period-anchored vs in-window BEIS Domestic DSR Competition (2018)	Internally modelled with reference to post-2017 comparators. No 2017 primary source exists. If the incentive required to achieve target penetration is higher, operating costs increase proportionally.
A20	Customer acquisition and onboarding - £60/HH	Internal modelling	Internally modelled. Actual costs depend on channel strategy and community engagement dynamics.
A21	Maintenance - £31/HH/yr	Internal modelling	No published benchmark. Conservative relative to commercial smart home service plans at approximately £99/yr.
A22	Fixed overhead - £85,100/yr	ONS ASHE 2017; HMRC NI 2017/18	Based on ONS ASHE 2017 median salary benchmarks. Actual staffing costs may differ depending on recruitment outcomes and deployment location.
A23	Device lifetime - 12 years	Dimplex Quantum manufacturer spec	Within the manufacturer's stated 10–15 year range. If devices require earlier replacement, amortised capex per year increases.
A24	Discount rate - 10% for NPV	Internal modelling	Standard internal modelling assumption. A higher rate reduces NPV; a lower rate increases it.
A25	Warmer Homes Scotland avg grant - £4,572/HH	Scottish Govt HEEP Annual Review 2016/17	Average figure from 2016/17. Eligibility criteria and grant values may change in future funding rounds.

	Household Economics		
A26	Sc.A consumption - 5,040 kWh/yr (4,200 × 1.2 Orkney uplift)	Ofgem TDCV August 2017 - uplift internal modelling	The 1.2× Orkney uplift is internally modelled with no published source. If actual consumption is lower the incentive proposition is marginally weaker; if higher, stronger.
A27	Economy 7 off-peak rate - 7.5p/kWh (derived)	Ofgem prepayment cap Apr-Sep 2018	Derived rather than directly observed. Full derivation in AppendixFinancialModel.3. Actual rates vary by supplier and tariff.
A28	Economy 7 peak rate - 16.0p/kWh	Ofgem prepayment cap Apr-Sep 2018	Same limitation as A27.
A29	Day/night consumption split - 58% day / 42% night	Ofgem TDCV August 2017	Based on Ofgem Profile Class 2 typology. Individual household split may vary materially from this average.
A30	Sc.B heating demand - 12,000 kWh/yr	Ofgem TDCV August 2017 - gas medium proxy	Gas medium proxy applied to an off-gas household context. Actual heating demand varies with dwelling size, insulation and occupancy.
A31	Oil price - 39.17p/litre (2017 annual average)	BEIS QEP Table 4.1.2, 2017	Annual average used. Seasonal variation means actual household costs differ across the year.
A32	Oil calorific value - 10.18 kWh/litre	BEIS GHG conversion factors 2017	No limitation. Standard BEIS published conversion factor.
A33	Oil boiler efficiency - 85%	HHIC industry standard	Industry standard average. Actual efficiency varies with boiler age and maintenance condition.
A34	Wholesale electricity - £50/MWh	BEIS QEP H1 2018	H1 2018 price used as a 2017/18 proxy. Wholesale prices are volatile and this figure is a point estimate.
A35	ROC value - £41/MWh (0.9 ROCs × £45.58 buy-out)	Ofgem RO Guidance - Suppliers 2017/18	Only turbines accredited under the Renewables Obligation before 2015 retain ROC eligibility. The proportion of the Orkney fleet that qualifies is not confirmed.
A36	1.2× Orkney climate uplift on consumption	Internal modelling - no published source	Same limitation as A26. No published source identified for the Orkney-specific uplift factor.

A37	Grid carbon intensity - 280 gCO$_2$/kWh (2017)	BEIS GHG conversion factors 2017	No limitation. Standard BEIS published conversion factor for the relevant year.

Notes

- OREF EPC 2022 data is used as a proxy for 2017/18 heating mix. This is flagged as a limitation in **Section 12**.
- The 7.5p/kWh Economy 7 off-peak rate is derived rather than directly stated. See AppendixFinancialModel.3 for full derivation.
- The 1.2× Orkney climate uplift has no published source and is flagged in **Section 12** as a key modelling assumption.
- Sc.B installation cost (£250/HH) has no pre-2017 primary source and is flagged in **Section 12**.

Appendix A: Curtailment Operating State Examples

Table A.1 illustrates simplified numerical examples for the four operating states described in Section 4.2. These examples are conceptual only and are intended to demonstrate how wind availability, turbine limits, and network absorption constraints interact under different operating conditions.

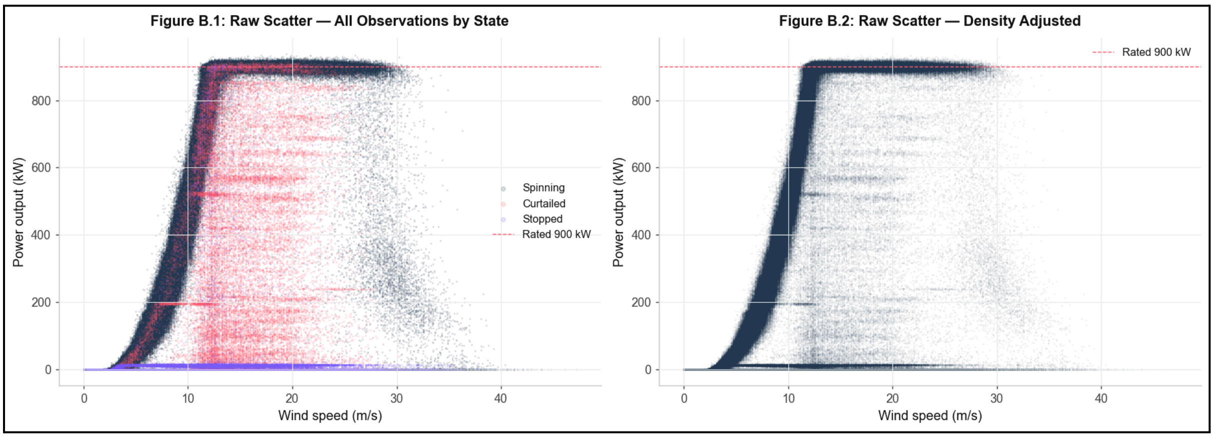
Operating State	Potential Power	System Absorption Capacity	Actual Output	Curtailed Energy	Explanation
Wind-limited	300kW	600kW	300kW	0kW	Insufficient wind resource prevent additional generation despite spare system absorption capacity.
Capacity-limited	1,200kW	>900kW	900kW	0kW	Output is capped at the turbine's rated capacity despite sufficient wind and network absorption capability.
Demand-limited	500kW	300kW	300kW	200kW	Available renewable generation exceeds the system's absorption capability, resulting in curtailment.
Capacity- and demand-limited	1,400kW	700kW	700kW	700kW	Both turbine operating limits and network absorption constraints influence realised output simultaneously.

Table A.1: Curtailment Operating State Examples

Appendix B: Power Curve Construction and Validation

Appendix B.1 - Raw Scatter

The telemetry dataset contains 1,064,219 one-minute observations spanning May 2015 to January 2018. ***Figures B.1*** and ***B.2*** plot realised turbine output (`Power_kw`) against wind speed (`Wind_ms`) across the full dataset. ***Figure B.1*** colours observations by operational state, while ***Figure B.2*** uses transparency to show data density, with darker regions indicating a higher concentration of observations.



Figures B.1 and B.2: Realised turbine output against wind speed.
Figure B.1: operational states. Figure B.2: density-adjusted scatter.

A **power curve** is a blueprint that tells you exactly how much electricity (in kilowatts, or kW) a wind turbine can generate at different wind speeds (measured in meters per second, or m/s). **Cut-in threshold (2.5 m/s)** refers to the minimum wind speed at which the turbine begins generating power; below this, output is zero. **Storm-control taper (28 to 34 m/s)** is the wind speed range over which the turbine progressively reduces output to protect itself from damage, reaching zero at 34 m/s.

Several important operating characteristics are immediately visible. The relationship between wind speed and power output is strongly non-linear: output rises steeply between approximately 3 and 12 m/s before plateauing near the turbine's rated capacity of 900 kW. Above approximately 28 m/s, recorded output begins to decline, broadly consistent with the Enercon E-44's storm control behaviour. The density-adjusted scatter in ***Figure B.2*** makes the upper envelope of this S-curve particularly clear.

The dataset is dominated by spinning observations (88.6%), while stopped periods account for 8.4% and curtailed observations represent 2.9% of all records. Curtailed and stopped observations form distinct horizontal bands across multiple wind speeds, including periods of high wind availability. This indicates that a substantial portion of apparent underperformance is grid-driven rather than wind-limited, and that the raw scatter cannot be used directly to reconstruct the unconstrained power curve without filtering.

Appendix B.2 - Filtering Unconstrained Records

Reconstructing the unconstrained power curve requires isolating observations where the turbine was operating without an active network constraint. The unconstrained training sample was therefore restricted to observations where `Setpoint_kw = 900` (no active network constraint), `Power_kw > 0` (turbine generating), `Wind_ms > 0` (wind resource present), and `Power_kw <= Setpoint_kw` (removes transient overshoots above rated capacity). Together, these conditions identify periods where no explicit setpoint reduction was applied, the turbine was actively generating, and wind resource was present, while also removing transient overshoots where blade momentum briefly drives output above the setpoint. These overshoots would otherwise bias the empirical upper envelope above the turbine's rated capacity of 900 kW.

Applying these filters reduces the dataset from 1,064,219 observations to 785,075 unconstrained records (73.8%), with 279,144 observations excluded from power curve estimation.

One important caveat applies to the first condition - a setpoint of 900 kW indicates no explicit operator reduction, but it does not guarantee unconstrained operation. At low wind speeds, output naturally remains well below 900 kW regardless of the setpoint. These observations are not curtailed, but many still fall below the turbine's maximum achievable output at that wind speed. This issue is addressed in the following step (**Section 5.2**) by estimating the upper envelope within narrow wind speed bins rather than treating all unconstrained observations as representative of potential generation.

Appendix B.3 - Binned P50 / P90 / P95

The unconstrained observations were grouped into 0.5 m/s wind speed bins to estimate achievable turbine output under similar wind conditions. Within each bin, three quantile estimators were calculated: P50 (median), P90 (90th percentile, base case), and P95 (95th percentile, upper sensitivity). Bins containing fewer than 50 observations were excluded to reduce instability from sparse high-wind observations, yielding 66 usable bins spanning 2.5 to 35.0 m/s.

The choice of P90 as the base-case estimator reflects the analytical objective of approximating the upper envelope of unconstrained turbine performance. Even within the unconstrained sample, individual observations fall below maximum achievable output due to ramp-up transients, turbulence, wake interaction, sensor noise, and normal operating variation. The median (P50) therefore understates potential generation because it reflects typical realised performance rather than the upper envelope of achievable output. P95 is retained as an upper sensitivity bound.

The sample bin statistics confirm the expected operating pattern. At 5 m/s, P90 is 77 kW against a P50 of 56 kW, reflecting the wide spread of realised outputs at intermediate wind speeds. By 13 m/s, both P90 and P95 reach the 900 kW rated limit while P50 remains slightly lower at 895 kW, consistent with median output naturally falling fractionally below rated capacity under normal operating variation. ***Figure B.3*** plots the three estimators against the unconstrained scatter up to 28 m/s. Wind speeds above 28 m/s are excluded from the empirical estimator plot because observations become sparse and the storm-control taper in this region is imposed later as a physical operating constraint based on the published Enercon E-44 specification.

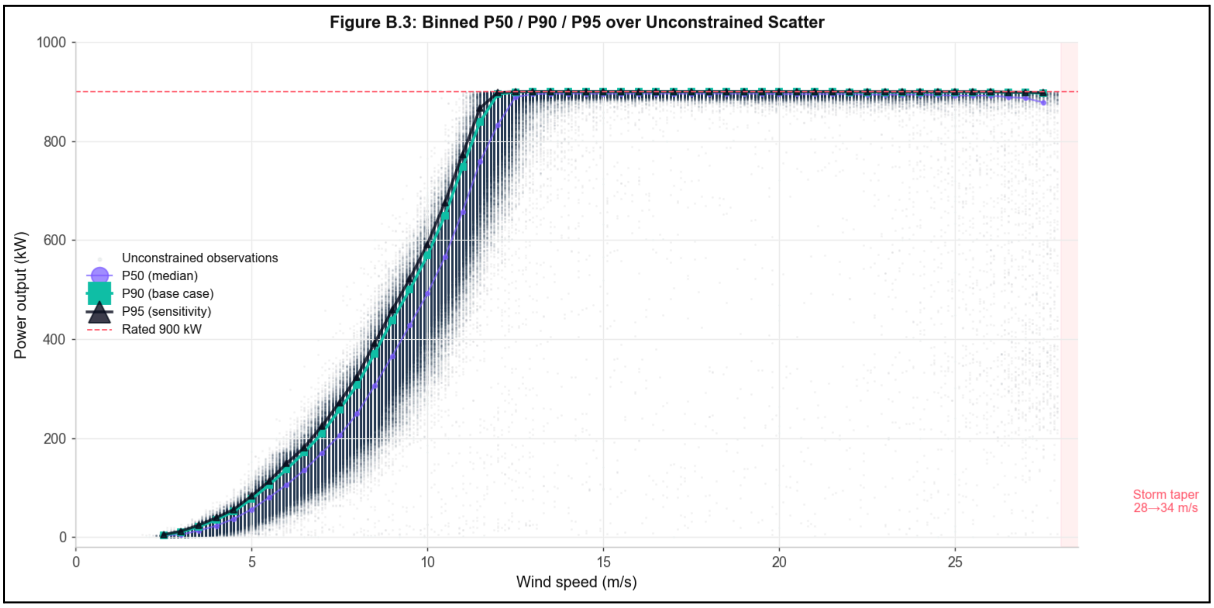


Figure B.3: Binned P50, P90, and P95 estimators over unconstrained observations. The P90 curve is used as the base-case estimate of unconstrained turbine performance.

Appendix B.4 - Spline Fitting and Physical Constraint Enforcement

The binned P50, P90, and P95 estimators were converted into continuous interpolation functions using cubic smoothing splines. A smoothing factor of $s = n \times 50$ was applied, where n is the number of wind speed bins. Lower smoothing values produced oscillations across the 6 to 12 m/s rising region, while higher values excessively flattened the curve and weakened the expected cubic relationship between wind speed and turbine output. The selected smoothing factor provided a stable fit that tracked the bin centres without introducing visible artefacts.

Physical operating constraints were then imposed directly on the interpolated curves to ensure consistency with the published Enercon E-44 operating specification. Output was constrained to zero below the turbine's 2.5 m/s cut-in wind speed. A hard plateau of 900 kW was enforced from approximately 12.5 m/s to 28 m/s by overriding the spline output directly, correcting for minor deviations that arise because observations become sparser at higher wind speeds and the spline prioritises smoothness over a perfectly flat plateau. Above 28 m/s, a linear storm-control taper was imposed, reducing output progressively from 900 kW at 28 m/s to zero at the 34 m/s cut-out threshold.

The resulting interpolation functions exhibit the expected non-linear operating behaviour. Under the P90 base case, estimated potential output rises from 10.6 kW at 3 m/s to 575.4 kW at 10 m/s before reaching the rated plateau near 12 to 13 m/s. The imposed storm-control region then reduces output to 600 kW at 30 m/s, 300 kW at 32 m/s, and zero at 34 m/s. The close alignment between the P90 and P95 curves across most wind speeds further indicates that the estimated upper envelope is stable and not excessively sensitive to the percentile threshold.

Appendix B.5 - Validation and Sensitivity

Figures 5.1 *(*[Section 5](#)*)* and ***B.4*** were used to validate the reconstructed power curve and assess its stability across alternative specifications and operating conditions. ***Figure 5.1*** overlays the fitted P50, P90, and P95 interpolation functions on the unconstrained scatter sample. The fitted curves track the upper envelope of observed turbine behaviour closely across the full operating range, while the imposed physical constraints produce the expected operating profile: zero output below the 2.5 m/s cut-in threshold, a stable rated plateau near 900 kW through the normal operating region, and a linear storm-control taper between 28 and 34 m/s.

The fitted curves also demonstrate that the reconstruction is relatively insensitive to the chosen percentile threshold. Across the main operating region, the P90 and P95 curves are almost indistinguishable, indicating that the estimated upper envelope is stable and not driven by a small number of extreme observations. The P50 curve remains consistently below the upper-envelope estimators, particularly in the 6 to 12 m/s transition region where output variability is greatest. This supports the use of P90 as the base-case estimator for potential generation rather than the median or mean output.

Figure B.4 evaluates seasonal stability by reconstructing separate P90 curves for winter, spring, summer, and autumn and comparing them against the annual P90 curve. The seasonal curves align closely across almost the entire wind speed range, suggesting that the reconstructed relationship between wind speed and output is stable through time and not materially distorted by seasonal operating conditions or transient environmental effects. Minor divergence only appears at very high wind speeds where observations become sparse.

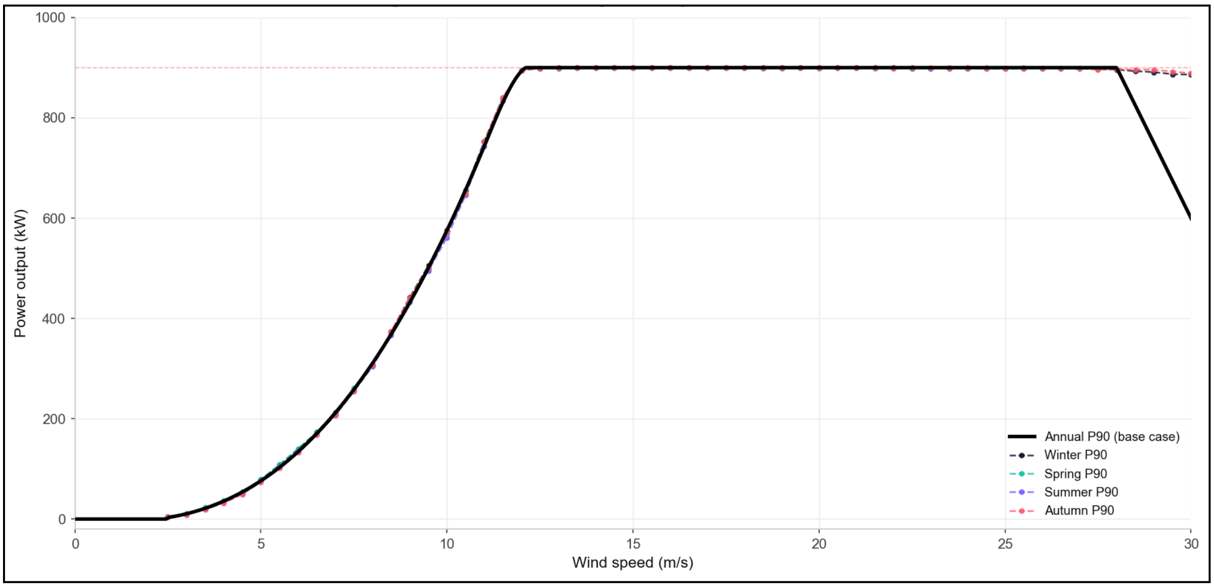


Figure B.4: Seasonal P90 power curves compared against the annual P90 reconstruction.

Sensitivity testing further confirms the robustness of the reconstruction. Applying the fitted interpolation functions across the full telemetry dataset yields estimated total potential generation of 7.851 GWh under the P50 specification, 8.473 GWh under the P90 base case, and 8.651 GWh under the P95 upper-bound specification. Relative to the P90 base case, the P50 estimator reduces estimated potential generation by 7.9%, while the P95 estimator increases it by only 2.1%. The relatively narrow spread between the P90 and P95 estimates indicates that the reconstructed upper envelope is not excessively sensitive to the percentile choice, supporting the use of P90 as a robust base case for downstream curtailment modelling.

Appendix C: Residential Demand Patterns

Appendix C.1 - Data Cleaning and Preparation

The residential demand dataset is used exclusively for demand pattern analysis and is not merged temporally with the turbine telemetry. Consistent with the assumptions register established in **Section 4**, the actual demand proxy used in the curtailment calculations is `Power_kw` from the turbine dataset.

The residential demand dataset contains 17,568 half-hourly observations spanning January 2017 to January 2018. After removing a single observation from 1 January 2018, the final analysis sample contained 17,520 records, equivalent to a complete year of uninterrupted 30-minute measurements. All timestamps were spaced consistently at 30-minute intervals, so no interpolation or gap-filling was required.

The dataset includes three variables: `timestamp`, mean household electricity demand (`Demand_mean_kw`), and the number of households contributing to each interval average (`N_households`). `N_households` was not used in the downstream analysis because the dataset is representative only and does not correspond directly to the total number of Orkney households. An anomalous increase in sample size during September 2017 and October 2017 was treated as a data quality issue rather than a genuine demand shift.

An outlier inspection using a three-standard-deviation threshold identified 21 observations above 0.489 kW per household. Manual inspection suggested that these observations corresponded to plausible winter evening peak-demand periods rather than erroneous measurements, so all records were retained.

To align the analysis with hourly demand patterns relevant for demand-response scheduling, the 30-minute observations were aggregated to hourly resolution by averaging the two observations within each hour. An energy conservation check confirmed that total annual demand was unchanged after aggregation. Month, hour-of-day, and seasonal indicators were then assigned to support the profile analysis in the following appendix section.

Appendix C.2 - Seasonal 24-Hour Profiles

The seasonal subplots in ***Figure C.1*** further highlight the concentration of residential demand during the early evening hours. In all seasons, minimum demand occurs between approximately 03:00 and 04:00, while peak demand occurs during the late afternoon or early evening.

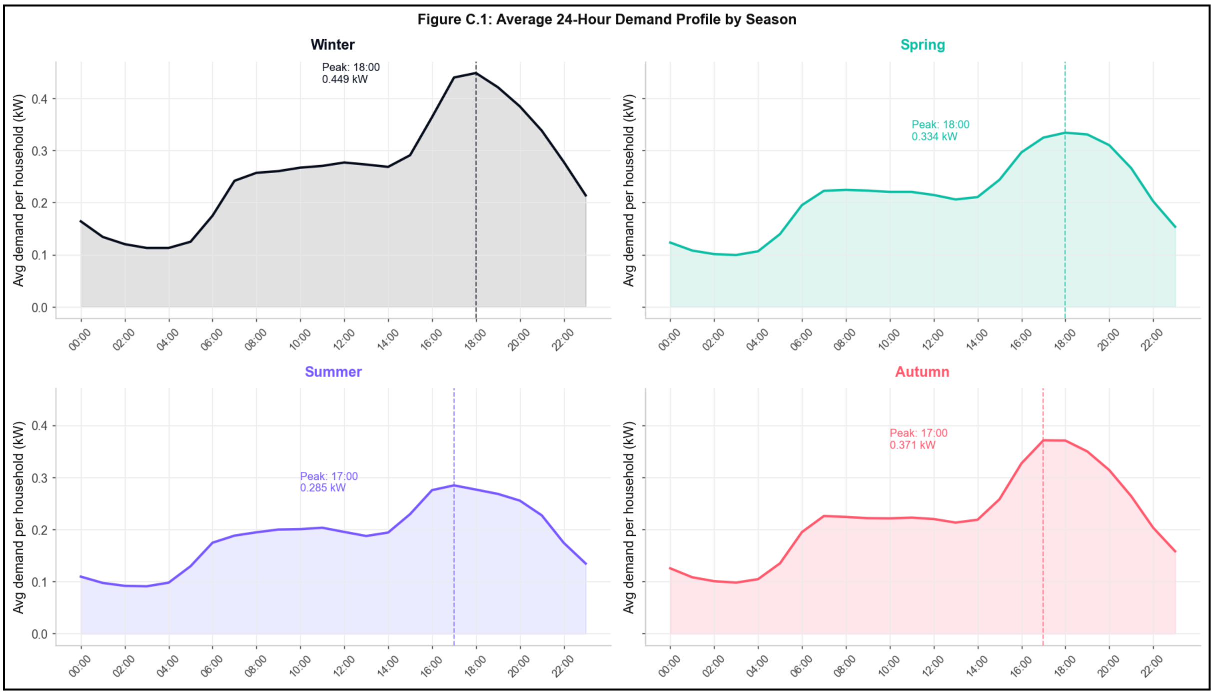


Figure C.1: Average 24-Hour Residential Demand Profile by Season

The heatmap in ***Figure C.2*** reinforces this pattern by showing that the strongest demand intensity is concentrated during the colder months, particularly between October and March. The implications of these demand patterns for demand-response scheduling are discussed in [Section 8](#).

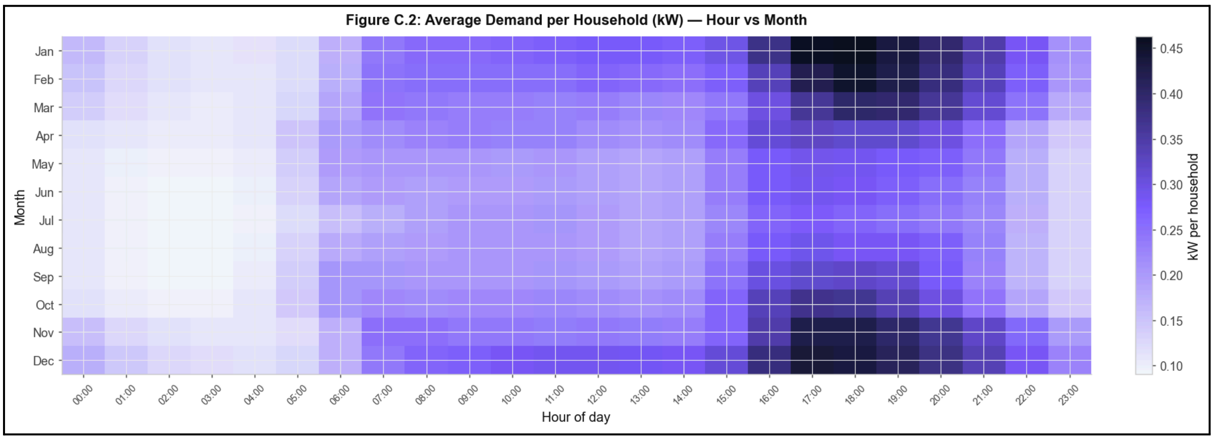


Figure C.2: Average Demand per Household (kW) - Hour of Day vs Month

Appendix C.3 - Monthly and Seasonal Demand Variation

Figure C.3 plots the monthly average residential demand per household across 2017. Demand follows a clear seasonal cycle, with the highest average consumption occurring during the colder winter months and the lowest occurring during summer. Average household demand rises progressively from late summer into autumn before peaking during December and January, consistent with increased heating and lighting requirements during winter months.

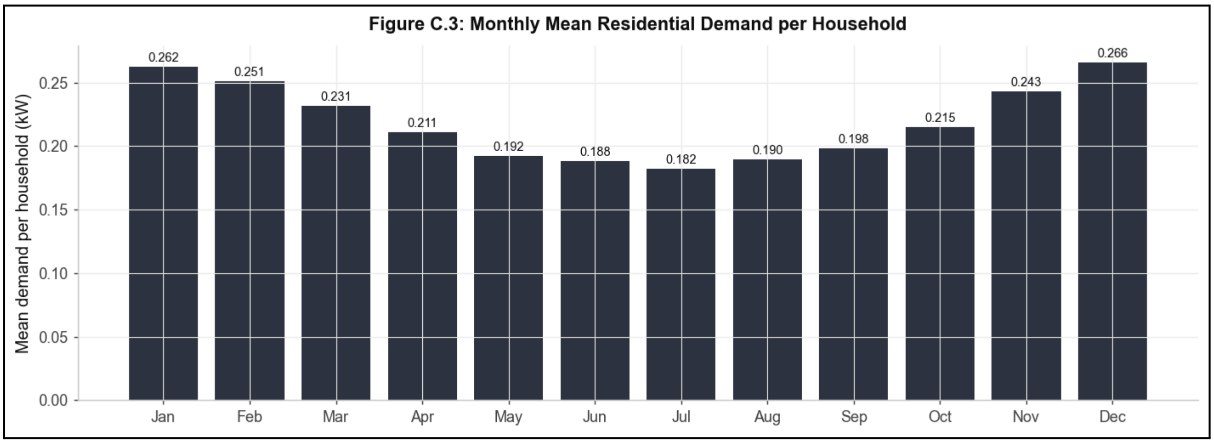


Figure C.3: Monthly Mean Residential Demand per Household

Seasonal mean household demand averaged 0.260 kW in winter, compared with 0.187 kW in summer, reinforcing the materially higher residential electricity requirements observed during colder months.

Appendix D: Curtailment Analysis

Appendix D.1 - Curtailment Calculation Framework

The reconstructed P90 power curve from **Section 5** was applied to the raw one-minute turbine telemetry to estimate unconstrained potential generation at each observed wind speed. The resulting potential-generation series was combined with realised turbine output to construct the hourly curtailment dataset using the framework established in **Section 4**.

The telemetry series was aggregated to hourly resolution by averaging all valid observations within each hour. Hours containing no valid observations were excluded, producing a final sample of 17,852 hourly observations spanning 2.63 years. The single-turbine series was then scaled to a 600-turbine fleet, equivalent to 540 MW of installed wind capacity, by multiplying the hourly per-turbine series by N = 600.

The hourly curtailment series was decomposed into two components. The setpoint-driven component captures hours where the network-operator-issued setpoint was below potential generation. The below-setpoint component reflects deviations between commanded and realised output caused by operational response delays and short-term wind variability.

The telemetry contains 3,720 stopped-state episodes where Setpoint_kw = 0. Of these, 95.3% last under one hour with a mean wind speed of 14.4 m/s, while the eight episodes exceeding 24 hours recorded a mean wind speed of 10.0 m/s.

All annual figures in **Section 7** were annualised over the observed 2.63-year span.

Appendix D.2 - Annual Summary

Applying the reconstructed P90 power curve across the 2.63-year telemetry span yields estimated annual potential generation of 1,945.7 GWh/yr, of which 1,495.8 GWh/yr is ultimately realised. The remaining 450.4 GWh/yr, equivalent to 23.1% of total potential generation, is curtailed due to network constraints.

At a wholesale electricity value of £55/MWh, the curtailed energy corresponds to approximately £24.8 million of annual unrealised generation value. This represents the generator-side value of lost renewable output rather than Kaluza revenue. Within the curtailment total, 268.1 GWh/yr (59.5%) is associated with explicit network-operator setpoint reductions and therefore represents the demand-response-addressable pool. The remaining 184.3 GWh/yr (40.9%) reflects below-setpoint deviations caused by operational response delays and short-term wind variability.

The export cable reaches or exceeds its 40 MW capacity during 75.4% of all observed hours, reinforcing that curtailment is driven primarily by persistent structural network congestion rather than isolated peak events.

Appendix D.3 - Seasonal Curtailment Patterns

Figures D.1a and ***D.1b*** summarise the annualised seasonal curtailment profile across the representative Orkney fleet. Autumn records the largest absolute curtailment volume at 145.3 GWh/yr, equivalent to 32.3% of annual curtailed energy, followed by summer at 131.9 GWh/yr and spring at 96 GWh/yr. Winter records the lowest curtailment volume at 76.9 GWh/yr despite exhibiting the highest average wind speed at 11.9 m/s.

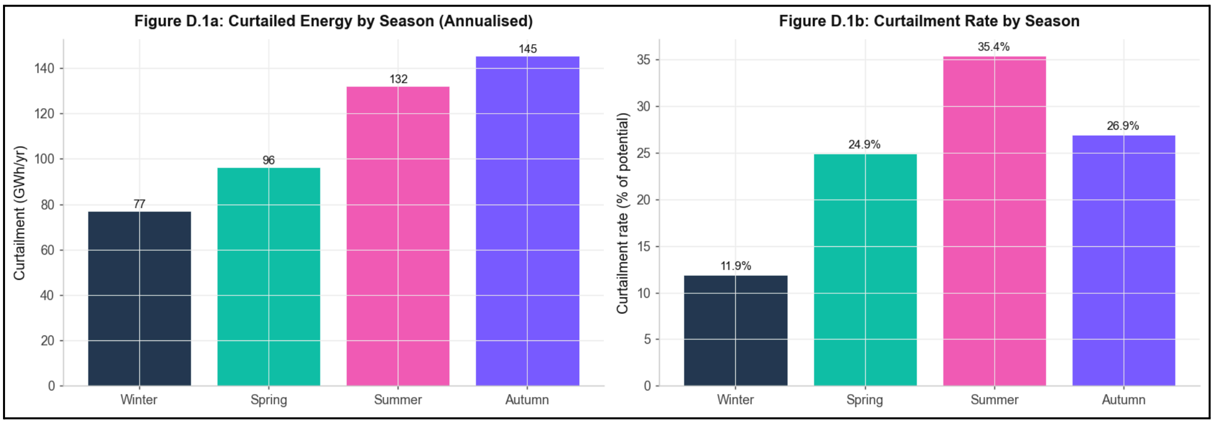


Figure D.1a: Curtailed Energy by Season (Annualised)

Figure D.1b: Curtailment Rate by Season

The seasonal curtailment rates in ***Figure D.1b*** highlight this counterintuitive relationship. Winter exhibits the lowest curtailment rate at 11.9%, while summer records the highest at 35.4% despite materially lower average wind speeds at 8.1 m/s. This reflects the interaction between wind availability and electricity-system absorption capacity. During winter, higher residential demand increases the volume of generation the system can absorb before network constraints bind. During summer, lower demand reduces absorption capacity, increasing the proportion of potential generation that is curtailed even under lower average wind conditions.

Appendix D.4 - Daily Curtailment Patterns

Figure 7.2 (**Section 7**) plots mean curtailment intensity by hour of day and month across the representative Orkney fleet. Curtailment is concentrated during the late morning and afternoon period rather than overnight, with mean curtailment peaking at 13:00 at 78.1 MW. Average daytime curtailment between 08:00 and 17:00 reaches 71.9 MW, compared with 63.6 MW overnight between 22:00 and 06:00.

The strongest curtailment intensity occurs during late summer and autumn, with hour-month cells in the August to October mid-afternoon period reaching mean intensities above 120 MW. Evening curtailment intensity declines materially after approximately 17:00.

April also exhibits several high-intensity cells relative to the surrounding months. However, April hour-month cells are based on an average of 39.5 observations per cell compared with approximately 62 observations for August and October, so the apparent April intensity should be interpreted cautiously.

The primary curtailment window in Orkney occurs during the late morning to mid-afternoon period, and these temporal patterns directly inform the device-scheduling strategies evaluated in **Section 8**.

Appendix D.5 - External Plausibility Check

The modelled fleet curtailment estimate was cross-checked against the published Heat Smart Orkney curtailment figure for the Rousay community turbine, which reported approximately 0.7 GWh of curtailed energy during FY 2016–17. Scaling this figure across the representative 600-turbine fleet implies annual fleet curtailment of approximately 420 GWh/yr, compared with the modelled estimate of 450 GWh/yr.

The model therefore sits approximately 7% above the Rousay-implied fleet estimate. However, the Rousay turbine sits within Zone 1 of the SSEN ANM network, which experiences the highest curtailment exposure under the LIFO priority structure. Scaling the Rousay figure across the entire Orkney fleet therefore likely overstates average fleet-wide curtailment. Given the uncertainty surrounding total fleet size, spatial wind variation, and the use of a single-turbine extrapolation, the 7% difference is sufficiently small to support the overall plausibility of the reconstructed curtailment estimate.

Appendix D.6 - Missing Data Assessment

The hourly curtailment dataset contains 17,852 valid hourly observations out of 23,023 expected hours across the full telemetry span, implying 5,171 missing hours or 22.5% of the expected sample. Missing observations are not distributed uniformly through time. ***Figure D.2*** shows that data coverage remains near-complete during January to March and May, but deteriorates materially between April and November (excluding May).

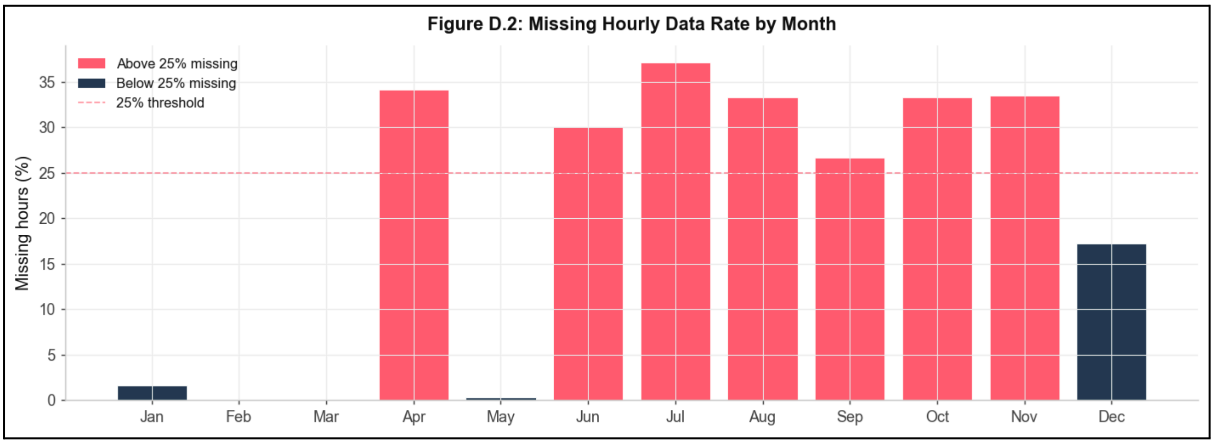


Figure D.2: Missing Hourly Data Rate by Month

The highest monthly missing-data rate occurs in July at 37.1%, while April, August, October, and November all exceed 33% missing coverage. By contrast, winter months exhibit substantially higher completeness, with January containing only 1.6% missing hours and February and March exhibiting complete coverage.

This uneven distribution implies that absolute curtailment estimates for spring, summer, and autumn are likely understated relative to the true underlying curtailment volume. Winter curtailment estimates are therefore considered the most reliable seasonal results within the dataset.

Appendix D.7 - Fleet Size Sensitivity

Figure D.3 evaluates the sensitivity of the annual curtailment estimate to the assumed number of turbines in the representative Orkney fleet. Under the base-case assumption of 600 turbines, annual curtailed energy is estimated at 450 GWh/yr. Reducing the fleet assumption to 500 turbines lowers annual curtailment to 375 GWh/yr, while increasing the fleet to 700 turbines raises curtailment to 526 GWh/yr.

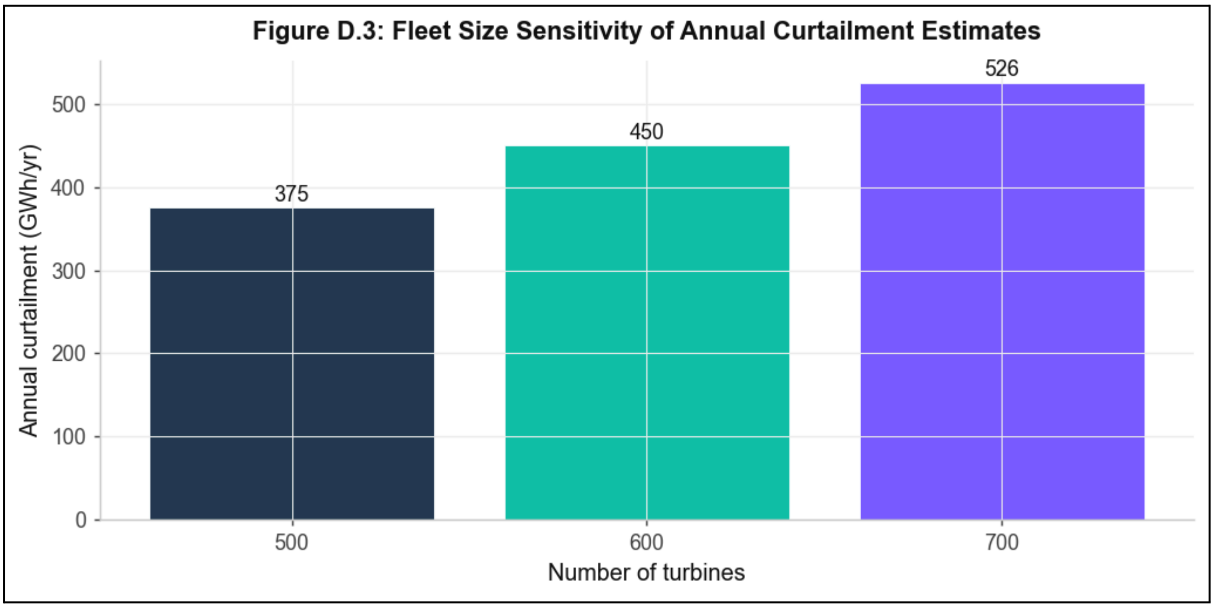


Figure D.3: Fleet Size Sensitivity of Annual Curtailment Estimates

The implied per-turbine annual curtailed energy remains stable at approximately 751 MWh/yr across all scenarios, with a constant curtailment rate of 23.1%. The sensitivity analysis therefore primarily affects the absolute scale of recoverable energy rather than the underlying curtailment dynamics.

Appendix E: Commercial Deployment Strategy

Appendix E.1 - SSEN Constraint Managed Zone Framework

SSEN's Constraint Managed Zone framework was introduced in 2016 as the first flexibility procurement mechanism operated by a UK Distribution Network Operator (SSEN, 2016). The framework identifies geographic zones where network constraints limit the export of electricity and procures demand response services from aggregators to manage those constraints without immediate grid reinforcement investment. Procurement is conducted through the Piclo flexibility marketplace, with aggregators submitting availability and dispatch offers in exchange for flexibility payments per MWh of demand shifted during constraint events. The relevant service category for the proposed Kaluza scheme is CMZ Prevent, which compensates aggregators for reducing demand or increasing local consumption during periods when network export constraints would otherwise cause curtailment. Under this structure, Kaluza would participate as a flexibility aggregator, combining demand from multiple households into a single flexible resource capable of meeting minimum procurement thresholds. The framework was formally active during the analysis period, as confirmed by a procurement notice published on the EU Tenders Electronic Daily on 27 July 2017 (European Commission, 2017). The flexibility payment benchmarks used within the financial model are derived from procurement activity conducted under this framework and are discussed further in **Section 9**.

Appendix E.2 - Government Support Frameworks

Two government support mechanisms are relevant to the proposed deployment. Warmer Homes Scotland is a Scottish Government scheme funding energy efficiency and heating improvements for fuel-poor households, with an average grant of approximately £4,572 per household during 2016/17 (Scottish Government, 2017). Eligibility is income-based and targets households in or at risk of fuel poverty. The Energy Company Obligation (ECO2t) is a UK-wide scheme placing legal obligations on larger energy suppliers to fund energy efficiency measures in low-income and vulnerable households. Orkney's fuel poverty rate of 58% (Orkney Islands Council, 2016) indicates a substantial population potentially eligible for support under one or both frameworks, increasing the likelihood that a significant proportion of target households could access grant funding. Both frameworks are treated as deployment enablers rather than commercial foundations, and their impact on commercial viability is discussed further in the report.

Appendix F: Financial Analysis

Appendix F.1 - Cost Structure

The financial model distinguishes between upfront deployment capex and recurring annual operating costs. All figures are denominated in 2017/18 prices unless otherwise stated.

Device and installation costs differ materially between segments. Sc.A households require only a retrofit smart hub connected to an existing storage heater at a device cost of £100 per household (Project FAQ; Energy Brief, 2026). Sc.B households require full replacement with two Dimplex Quantum storage heaters at £600 each, giving a total device cost of £1,200 per household (Energy Brief, 2026; HeaterShop, 2017). Installation for Sc.A is estimated at £125 per household as the base case, adjusted approximately 17% downward from current Refurbb smart-heating installation benchmarks to reflect 2017/18 labour market conditions (Refurbb, 2024), while £150 per household is retained as an upper-bound sensitivity case. Sc.B installation is estimated at £250 per household for a full two-heater replacement including wiring, based on current Checkatrade installation benchmarks adjusted to reflect 2017/18 labour costs (Checkatrade, 2024); no directly comparable pre-2017 benchmark was identified and this assumption is flagged in **Section 12**. Total Sc.A capex is therefore £225 per household and Sc.B capex is £1,450 per household. The Dimplex Quantum carries a manufacturer-stated lifespan of 10 to 15 years; 12 years is used as the base case based on Dimplex manufacturer specifications unchanged since product launch. Orkney's remote archipelago geography introduces ferry delivery costs, limited local contractor availability, and elevated travel costs relative to mainland UK benchmarks; installation assumptions reflect these constraints and are intended to remain conservative. Full sensitivity across £100 to £175 per household for Sc.A installation is evaluated in **Section 10**.

Grant structure: Orkney's fuel poverty rate of 58% (Orkney Sustainable Energy Strategy, 2016) is assumed to determine the share of households assumed eligible for Warmer Homes Scotland grant funding, which covers the full device and installation cost for eligible households. The Scottish Government Home Energy Efficiency Programmes Annual Review 2016/17 records an average grant value of £4,572 per household under this scheme (Scottish Government, 2017). Applied to the full Sc.A household pool of 3,323 households, approximately 1,927 households are fully grant-funded and 1,396 households are Kaluza-funded at a total non-eligible Sc.A capex of £314,100. For Sc.B, approximately 1,686 households are fully grant-funded and 1,222 households are Kaluza-funded at a total non-eligible Sc.B capex of £1,771,900. Additional government subsidy scenarios of 0%, 25%, 50%, and 75% applied to non-eligible capex are evaluated in **Section 10**.

Operating costs are modelled internally where no directly comparable 2017/18 Orkney residential demand-response benchmark was identified. Annual maintenance is estimated at £31 per household per year and is flagged as a key uncertainty in **Section 12**. The participation incentive is modelled at £80 per household per year as the base case, representing the assumed payment required to achieve meaningful household enrolment given the absence of upfront device costs. The incentive is split 60/40 between Kaluza (£48 per household per year) and government (£32 per household per year), with this split treated as an internal modelling assumption. Sensitivity is tested at £50, £80, and £100 per household per year, with £100 treated as an upper-bound sensitivity case. Both the incentive level and the 60/40 split are flagged as key uncertainties in **Section 12**. The combined Kaluza operating cost per enrolled household is £79 per household per year. A one-off acquisition and onboarding cost of £60 per household is applied at enrolment, comprising £40 for customer acquisition and £20 for a three-month onboarding incentive period, both modelled internally.

Fixed annual overhead totals £85,100 per year. This comprises an operations manager at £40,880 and a customer support role at £29,200, including employer National Insurance and pension contributions based on 2017/18 UK rates (ONS ASHE, 2017; HMRC, 2017). Platform hosting and monitoring is modelled at £7,500 per year, while travel, administration, and local liaison costs are modelled at £7,520 per year.

Item	Sc.A	Sc.B
Device	£100	£1,200
Installation (base)	£125	£250
Total capex (base)	£225	£1,450
Installation (upper bound)	£150	-
Total capex (upper bound)	£250	-
Device lifetime	12 years	12 years

Table F.1: Deployment Capex per household

Item	Value
Maintenance	£31/HH/yr
Participation incentive - Kaluza portion	£48/HH/yr
Kaluza opex per enrolled HH	£79/HH/yr
Customer acquisition (one-off)	£40/HH
Onboarding incentive (one-off)	£20/HH
Total one-off per HH	£60/HH

Table F.2: Annual Operating Costs (Kaluza-borne)

Item	Salary	NI (13.8%)	Pension (3%)	Total
Operations manager	£35,000	£4,830	£1,050	£40,880
Customer support	£25,000	£3,450	£750	£29,200
Platform hosting	-	-	-	£7,500
Travel, admin, liaison	-	-	-	£7,520
Total				£85,100

Table F.3: Fixed Annual Overhead

Appendix F.2 - Revenue Streams

A base-case flexibility value of £250/MWh is adopted using early SSEN constrained-market-zone procurement benchmarks from 2017/18 (TED notice 292933-2017; SSEN CMZ launch documentation, 2016). A mature-market upside benchmark of £300/MWh is also considered using later SSEN/Piclo flexibility procurement results reported by The Energyst (2019). The base-case assumption therefore applies an approximate 17% discount relative to the mature-market benchmark in order to reflect the earlier-stage nature of residential flexibility markets during 2017/18, when provider competition and market liquidity remained limited. These values are treated as benchmark proxies rather than guaranteed contract prices.

A base-case generator service fee of £25/MWh is adopted as an internal modelling assumption. Under the conservative wholesale-only base case, generators retain £25/MWh of previously unrealised generation value after payment to Kaluza. For turbines accredited under the Renewables Obligation prior to 2015, retained value may increase to approximately £66/MWh once ROC income is included. Because curtailed generation currently earns £0/MWh, the service fee creates incremental revenue on otherwise worthless output with limited additional operational burden, making participation commercially rational regardless of ROC accreditation status.

The participation incentive of £80 per household per year is split between Kaluza and government support as described in **Appendix F.1**, and is funded through institutional flexibility revenues.

Appendix F.3 - Household Economics

Sc.A - Existing storage heater household. Annual electricity consumption is estimated at 5,040 kWh per year, derived from the Ofgem Typical Domestic Consumption Value for Economy 7 Profile Class 2 medium consumers of 4,200 kWh per year (Ofgem, August 2017), scaled by a 1.2 Orkney climate uplift factor to reflect higher heating demand on northern Scottish islands. This uplift is an internal modelling assumption with no directly comparable published benchmark and is flagged in **Section 12**. The 58/42 day/night consumption split follows the Ofgem TDCV 2017 decision for Economy 7 households. Economy 7 tariff rates of 7.5p/kWh off-peak and 16.0p/kWh peak are derived from the Ofgem prepayment price cap for North Scotland, April to September 2018, and are treated as approximate estimates representative of 2017/18 conditions. Applying these rates yields a current annual electricity cost of approximately £626 per year (£52/month). After joining Kaluza, the household incurs no upfront device cost and receives a modelled participation incentive of £80 per year, giving a net annual benefit of £80 per year plus any additional saving from daytime curtailment scheduling.

Sc.B - Oil/coal household converting to storage heaters. Annual heating demand is estimated at 12,000 kWh per year using the Ofgem TDCV August 2017 medium gas-consumption value as a proxy for total space-heating demand in a medium off-gas Scottish home. The 2017 average oil price of 39.17p per litre (BEIS Quarterly Energy Prices, Table 4.1.2, 2017) combined with a kerosene calorific value of 10.18 kWh per litre (BEIS conversion factors, 2017) and a standard boiler efficiency of 85% (HHIC industry standard) yields an effective oil-heating cost of 4.53p per kWh of useful heat, giving a current annual oil cost of approximately £543 per year. Converting to Economy 7 storage heaters raises annual electricity expenditure to approximately £900 per year at the derived off-peak tariff rate of 7.5p per kWh. After inclusion of the £80 participation incentive, the net position versus the oil baseline remains approximately -£277 per year. At 2017/18 energy prices, oil heating is therefore materially cheaper per kWh than Economy 7 electricity, meaning Sc.B households are financially worse off after conversion at any modelled incentive level, as shown in ***Table F.4*** below. The Sc.B proposition therefore depends more heavily on grant-funded installation, improved heating reliability and control, and the wider decarbonisation and fuel-poverty objectives discussed in **Section 8**.

Table F.4 illustrates that no incentive level tested renders the Sc.B household position financially positive at 2017 energy prices, confirming that the proposition depends on non-financial drivers rather than direct cost savings.

Incentive	Sc.A net benefit	Sc.B net vs oil	Sc.B viable?
£50/yr	£50/yr	-£306.79/yr	No
£80/yr	£80/yr	-£276.79/yr	No
£100/yr	£100/yr	-£256.79/yr	No
£150/yr	£150/yr	-£206.79/yr	No

Table F.4: Net benefit of Sc.B across different incentive levels

Appendix G: DR Penetration and Commercial Viability

Appendix G.1 - DR Penetration

This section estimates the annual curtailment absorption achievable through a Sc.A demand response programme at varying levels of household enrolment. The simulation uses the DR-addressable curtailment profile derived in [Section 7] and evaluates six penetration scenarios ranging from 10% of households to the 32% Sc.A technical ceiling.

Absorption is calculated hourly as the minimum of: (i) available DR-addressable curtailment, (ii) maximum device output across enrolled households, and (iii) remaining daily thermal storage headroom. Three principal assumptions are applied. First, each enrolled household contributes 2.2 kW of flexible demand capacity based on the Dimplex Quantum RF input rating. Second, a 70% simultaneous availability factor is applied to reflect that not all enrolled households will be available to activate during every curtailment event. Third, a daily thermal storage limit of 10 kWh per household is used in the base case. A sensitivity scenario using a 15 kWh daily limit is also evaluated.

Table 10.1 (Section 10.1) reports enrolled households, flexible demand capacity, annual curtailment absorbed, and absorption as a share of the DR-addressable curtailment pool for each penetration scenario. Under the base-case assumptions, annual absorption increases from 646 MWh at 10% penetration to 2,023 MWh at the 32% Sc.A technical ceiling, equivalent to 0.24% and 0.75% of the DR-addressable curtailment pool respectively. Under the 15 kWh/day sensitivity, annual absorption increases to 2,762 MWh at the technical ceiling. ***Figures G.1a*** and ***G.1b*** present annual curtailment absorbed and absorption as a share of the DR-addressable pool by penetration level.

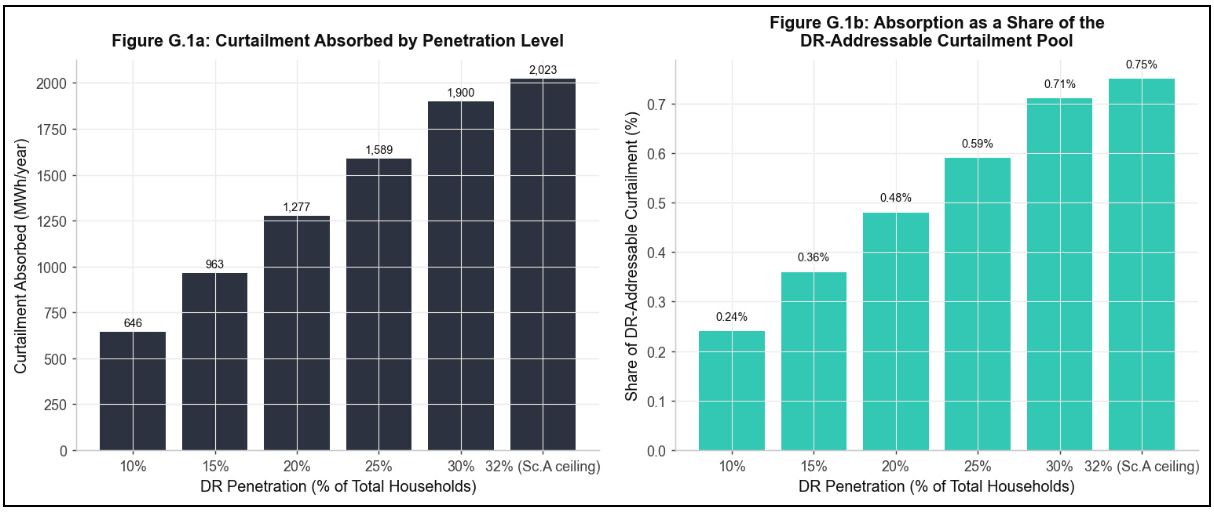


Figure G.1: Curtailment Absorption under Alternative Sc.A Penetration Levels

An additional output estimates the number of participating households required to achieve selected absorption targets. The model indicates that approximately 2,183 households (21.0% penetration) are required to absorb 0.5% of the DR-addressable pool, while achieving 1.0% would require participation beyond the 32% Sc.A technical ceiling.

Appendix G.2 - Commercial Viability Analysis

This section evaluates the commercial viability of a Sc.A demand response programme using the curtailment absorption outputs from Appendix G.1. Two complementary perspectives are considered: annual steady-state accounting profitability and a five-year cash flow projection that incorporates phased rollout costs. The base-case assumptions are SSEN flexibility payments of £250/MWh, a wind farmer service fee of £25/MWh, and no additional government subsidy beyond the baseline support already incorporated within the cost assumptions.

Annual accounting profit and loss is estimated using the absorbed MWh associated with each penetration scenario. Revenue comprises SSEN flexibility payments and wind farmer service fees, while costs include annualised capex, household incentives, maintenance, onboarding costs and fixed operating expenditure. ***Figure 10.1*** *(Section 10.2)* summarises annual revenue, cost and accounting profit across the penetration scenarios. Annual accounting profitability improves steadily with enrolment, increasing from a loss of £2,901 at 10% penetration to profits of £36,590, £75,257, £113,374 and £151,112 at 15%, 20%, 25% and 30% penetration respectively. At the 32% Sc.A technical ceiling, annual accounting profit reaches £165,918. The first accounting break-even point occurs at 15% penetration, equivalent to 1,558 enrolled households and 963 MWh of annual curtailment absorption.

The analysis also evaluates how subsidy support affects accounting viability. Under the base case and 25% subsidy scenarios, break-even remains at 15% penetration. Under the 50% and 75% subsidy scenarios, break-even is achieved at 10% penetration, with annual profits of £1,186 and £3,230 respectively. The minimum SSEN flexibility payment required for accounting profitability declines as participation increases, from £255/MWh at 10% penetration to £215/MWh at 15%, £195/MWh at 20%, £180/MWh at 25% and £175/MWh at 30% penetration.

A five-year cash flow projection is used to capture the impact of front-loaded rollout expenditure. The rollout assumes 30% of target households are enrolled in Year 1, 70% in Year 2 and 100% from Year 3 onwards. ***Figure 10.2*** (Section 10.2*)* presents cumulative cash flow trajectories across the penetration scenarios. Five-year cumulative cash flow remains negative at 10% penetration (£-118,564) and 15% penetration (£-14,058), but becomes positive at 20% (£87,148), 25% (£186,154) and 30% (£283,459) penetration. At the 30% penetration scenario, cumulative cash flow falls to £-145,804 during the rollout phase before recovering to £283,459 by Year 5. The corresponding net present value, using a 10% discount rate, is £156,819.

Appendix G.3 - Sensitivity Analysis

This section evaluates the sensitivity of the commercial viability model to changes in key assumptions. Unless otherwise stated, results are reported for the 30% Sc.A penetration scenario using the base-case assumptions of an SSEN flexibility payment of £250/MWh, a wind farmer fee of £25/MWh, and no additional government subsidy. Five sensitivity dimensions are considered: SSEN flexibility payment rate, wind farmer fee, government subsidy level, household participation incentive, and daily thermal storage capacity.

SSEN flexibility payment sensitivity is evaluated across rates ranging from £150/MWh to £400/MWh for each penetration scenario. At 30% penetration, annual accounting profit varies from £38,888 under the £150/MWh scenario to £436,112 under the £400/MWh scenario, compared with a base-case profit of £151,112. Wind farmer fee sensitivity is evaluated across fee levels of £0/MWh, £15/MWh, £25/MWh and £40/MWh. At 30% penetration, annual profit ranges from £103,612 at £0/MWh to £179,612 at £40/MWh.

Government subsidy sensitivity applies additional capital subsidies of 0%, 25%, 50% and 75% to non-grant-funded households. At 30% penetration, annual accounting profit increases from £151,112 under the base case to £157,248, £163,384 and £169,520 under the 25%, 50% and 75% subsidy scenarios respectively. Participation incentive sensitivity evaluates an increase in the Kaluza-funded household incentive from £48 to £60 per household per year. Under the higher incentive scenario, annual accounting profit at 30% penetration decreases from £151,112 to £113,720.

A thermal storage sensitivity is also evaluated by increasing the daily storage limit from 10 kWh/day to 15 kWh/day. Under this assumption, annual curtailment absorption increases from 1,900 MWh to 2,594 MWh at 30% penetration, increasing annual accounting profit from £151,112 to £341,962. ***Figure 10.3*** (**Section 10.3***)* presents a tornado chart summarising the change in annual accounting profit associated with each sensitivity variable relative to the base-case profit of £151,112 at 30% penetration.