



SCALING UTILITY-ENABLED DISTRIBUTED ENERGY RESOURCES FOR NIGERIAN COMMERCIAL & INDUSTRIAL (C&I) CUSTOMERS





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ABOUT US



ABOUT DAYBREAK POWER SOLUTIONS LIMITED (DAYSTAR)

Daystar Power, a member of the Shell Group, is a leading solar power service provider, offering hybrid solar power solutions for industrial and commercial customers in Africa, from small solar back-up systems to large megawatt size power plants. Daystar is committed to helping African businesses grow and develop by addressing their energy challenges. In doing so, Daystar provides clean and reliable power while significantly reducing clients' overall power costs. Daystar has installed over 58MW of power generation capacity across 380 systems in seven African countries including Nigeria, and is trusted by leading organizations like PepsiCo, Coca-Cola, Nestle, Olam, British American Tobacco, Rider Steel, United Nations, Ecobank among others.

ABOUT ROCKY MOUNTAIN INSTITUTE (RMI)

Rocky Mountain Institute (RMI) is an independent nonprofit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions by at least 50 percent by 2030. RMI has staff in over 25 countries, including teams based in Abuja and Lagos, Nigeria, and offices in Beijing; Basalt and Boulder, Colorado; New York City; Oakland, California; and Washington, D.C. RMI's Africa Energy Program works in sub-Saharan Africa to increase access to and productive use of sustainable electricity.





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EXECUTIVE SUMMARY

Funded by the United States Trade and Development Agency (USTDA), Daybreak Power Solutions Limited (Daystar) and Rocky Mountain Institute (RMI) conducted a feasibility study to optimize energy supply to 20 commercial and industrial (C&I) entities in Nigeria using utility-enabled distributed energy resources (DERs)ⁱ.

The objectives of this project were to identify a pipeline of 20 C&I projects, de-risk them by extensive technoeconomic analysis, regulatory assessment, design acceptable contract terms, facilitate customer-developer-distribution companies (DisCos) partnerships, and ultimately prepare projects for implementation.



ⁱ DERs are demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the loads served by that system, and include technologies such as solar PV, battery storage, and small-scale generators.

Figure ES 1 Overall scope of the feasibility study

We begin with
IDENTIFY...

- 1 **Identify the 20 optimal C&I customers** from Daystar and DisCo's pipeline and engage customers to facilitate project development.
- 2 **Interface with DisCos** to contextualize the project within their business strategy.
- 3 Design the **technical solutions** for each project in the pipeline, including the DER system and integration with the utility's grid.
- 4 Perform the **financial analysis** to ensure that the projects meet investor needs.
- 5 Conduct **regulatory assessment** to support project implementation.
- 6 Create the **contract terms** that ensure economic viability for projects and stakeholders.

...and end with
IMPLEMENTATION

- 7 Conduct a preliminary **environmental and social impact assessment** for each site.
- 8 Finalize an **implementation plan** to ensure de-risked projects are successfully implemented.
- 9 **Create the scaling strategy** so that Daystar can quickly execute on an expanded pipeline of projects and accelerate market growth.

The project successfully identified and completed the feasibility study for 20 potential C&I customers in Abuja and Lagos under three DisCo territories, namely Abuja Electricity Distribution Company (AEDC), Eko Electricity Distribution Company (EKEDC), and Ikeja Electric (IE). These projects represent a total of 27 MW in new solar capacity, \$43 million in capital investment, and an estimated 25,000 metric tons of CO₂e in annual greenhouse gas (GHG) emissions reductions. The proposed utility-enabled business model has strong potential to reduce energy costs for customers by replacing the burning of diesel and petrol through self-generation with DER systems, and increase

DisCo revenue by enabling more grid consumption and connecting new customers to the grid. At scale, the business model can potentially apply to 170,000 C&I customers across Nigeria, eventually unlocking 3.3GW of solar capacity and \$6.5 billion investment opportunity.

Despite constraints resulting from the new administration's monetary policy affecting foreign exchange (FX) in Nigeria, customer and DisCo engagement delays and post-COVID-19 pandemic, a few projects in the pipeline are well positioned for immediate deployment subsequent to the USTDA-funded study.

¹ DERs are demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the loads served by that system, and include technologies such as solar PV, battery storage, and small-scale generators.



NIGERIAN POWER SYSTEM AND C&I SECTOR CONTEXT

Due to inadequate generation capacity and electricity infrastructure across Nigeria, the bulk grid remains unreliable for the majority of customers. In some areas, it's common to have blackout for hours daily and transmission and distribution networks can collapse frequently. This is particularly problematic for C&I customers who require reliable and affordable power supply for their business operations. With poor grid services quality, many of these customers currently revert to diesel-fired generators as main or sometimes sole supply of electricity, bearing cost that can be twice as expensive as grid tariffs. With growing and unstable fuel prices, customers are increasingly looking at alternative DER solutions.

In recent years, Daystar among other DER developers had encouraging success deploying solar-based solutions to C&I customers. These systems are installed without the involvement of the DisCos, which is a missed opportunity as leveraging available low-cost grid supply can improve cost effectiveness, making projects more attractive for customers. Innovative business models can enable customers, developers, and DisCos to all benefit from C&I DER projects in a win-win-win scenario.

UTILITY-ENABLED C&I BUSINESS MODEL AND PIPELINE PROJECTS

The proposed utility-enabled business model will leverage the reliability benefits of distributed power, such as solar and batteries, and the increased grid electricity consumption, to better serve C&I customers, replacing expensive diesel usage. This model requires no upfront capital investment from the customer. Daystar, as the developer, is responsible for securing financing and installing and operating the DER system on-site to provide power supply during daytime peak hours (9am to 3pm). The DisCos, on the other hand, are expected to increase hours of grid supply to provide energy to the customer in the evening, night and early morning hours (3pm to 9am). Grid interruptions can be backed up through the batteries and

generators, delivering high reliability with a lower overall cost than generator-only backup systems.

In developing a pipeline of C&I projects, RMI identified dozens of potential customers and prioritized 20 C&I customers for technoeconomic analysis and further de-risking. The economic modeling showed that economic impact is positive for 17 of the 20 customers, with an average savings of 26% under current market conditions. For the remaining three customers, estimated energy costs increased mainly because they reported high grid consumption now. Still, the improved reliability is valued by customers and our sensitive analysis revealed that if certain market conditions change (e.g., diesel cost, battery cost, FX) rate), these projects would offer cost savings to customers. For DisCos, profitability could grow significantly, from 8% to 1,000%.



Figure ES 2 Illustration of the proposed utility-enabled C&I business model

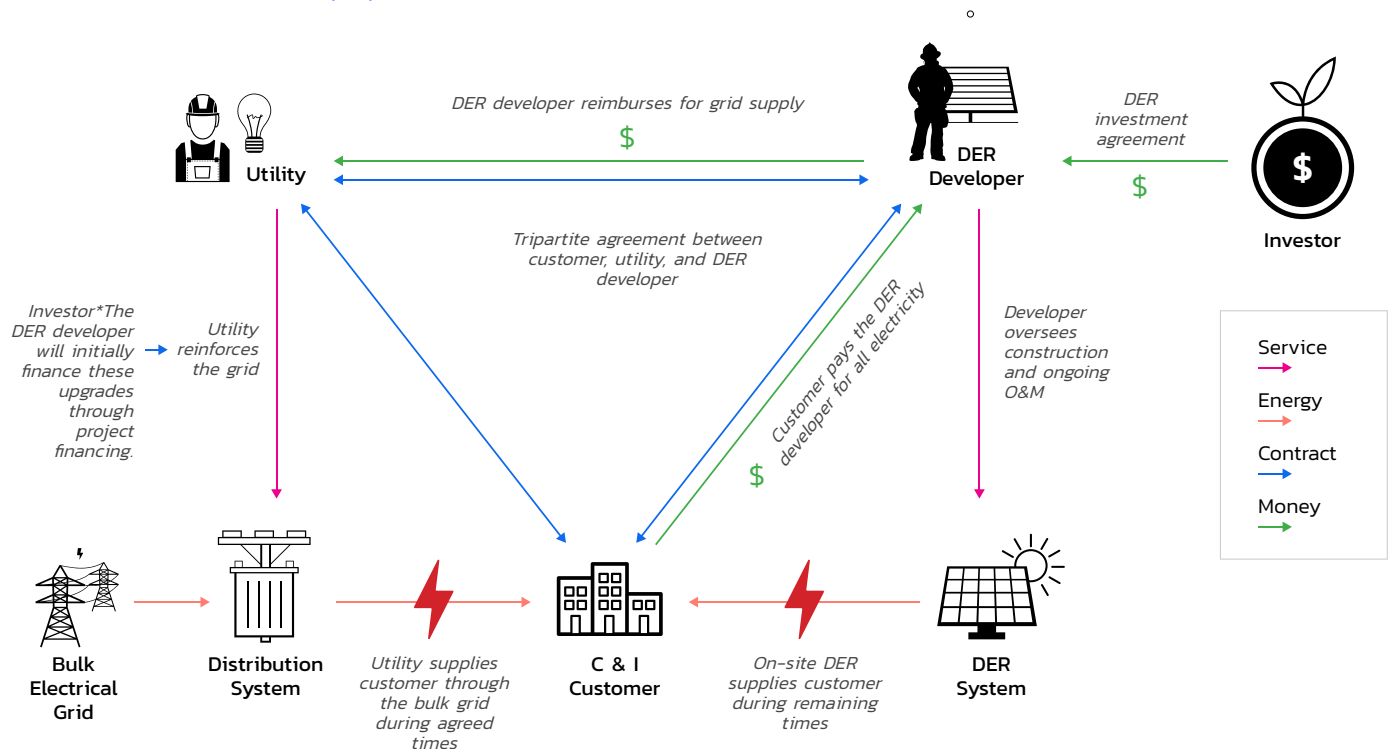


Table ES 1 Summary of DER system design and the economic impact

COMPANY ⁱⁱ	SYSTEM SIZING			CUSTOMER ENERGY COST SAVINGS(%)	DISCO PROFITABILITY GROWTH (%)	EMISSION REDUCTION (%)
	SOLAR	BATTERY	DIESEL/ GAS			
[Customer 1]	7,973 kW	6,219 kWh	N/A	44	100	35
[Customer 2]	4,500 kW	3,724 kWh	N/A	28	93	39
[Customer 3]	5,003 kW	3,730 kWh	3,000 kW	37	1,022	47
[Customer 4]	3,001 kW	2,265 kWh	1,700 kW	40	226	48
[Customer 5]	1,521 kW	816 kWh	617 kW	42	831	53
[Customer 6]	450 kW	592 kWh	591 kW	34	359	38
[Customer 7]	513 kW	162 kWh	396 kW	(35)	(14)	80
[Customer 8]	802 kW	515 kWh	345 kW	15	150	82
[Customer 9]	594 kW	600 kWh	N/A	44	100	76
[Customer 10]	559 kW	146 kWh	257 kW	(3)	10	85

ⁱⁱ The order of customers listed here is ranked based on customer demand.



COMPANY ^{II}	SYSTEM SIZING			CUSTOMER ENERGY COST SAVINGS(%)	DISCO PROFITABILITY GROWTH (%)	EMISSION REDUCTION (%)
	SOLAR	BATTERY	DIESEL/ GAS			
[Customer 11]	621 kW	362 kWh	230 kW	21	27	79
[Customer 12]	321 kW	235 kWh	210 kW	8	41	81
[Customer 13]	135 kW	270 kWh	164 kW	37	261	43
[Customer 14]	350 kW	247 kWh	165 kW	19	8	64
[Customer 15]	385 kW	182 kWh	172 kW	12	44	74
[Customer 16]	106 kW	45 kWh	54 kW	12	(19)	97
[Customer 17]	113 kW	44 kWh	93 kW	(27)	(46)	99
[Customer 18]	50 kW	75 kWh	80 kW	16	113	48
[Customer 19]	103 kW	77 kWh	77 kW	28	60	50
[Customer 20]	75 kW	64 kWh	68 kW	5	36	68

IMPLEMENTATION AND SCALING OUTLOOK

For the 20 pipeline projects, RMI has prepared draft contracts and implementation plans to guide the execution of projects and continuous engagement with customers and DisCos. For a few customers, especially with a furniture manufacturer in Abuja, Daystar are in the late stage of contract negotiation and hopeful for procurement and deployment to kick off in early 2024. Once the initial batch of projects are implemented and proven viable, we also estimated a conservative scaling scenario where 36 such projects can be implemented every year with Daystar's current operation size, adding an estimated of 17MW solar installed capacity to Daystar's portfolio annually. In a more optimistic scenario in which Daystar double its operational capacity, 72 projects or 34MW solar could be deployed per year.



01

**INTRODUCTION,
KICK-OFF MEETING,
AND INFORMATION
GATHERING**



This final report contains a comprehensive summary of the work completed under the USTDA-funded project, **Feasibility Study: Scaling Utility-Enabled Distributed Energy Resources for Nigerian Commercial & Industrial (C&I) Customers** (grant number 1131PL21GH11165), to establish the feasibility of related to the proposed development of grid-connected distributed energy resources to optimize energy supply to 20 C&I entities in Nigeria for Daystar.

The report is divided into nine sections, which correspond to the tasks listed in the project's terms of reference.

SECTION 1

Summarizes the project scope, and the activities and results of Task 1- kick-off meeting and information gathering for this project.

SECTION 2

Describes the proposed utility-enabled C&I business model and considerations for adaptation; DisCo engagement and feedback; site selection process and criteria; methodology for the technical analysis; and analysis results for each customer including load assessment, sizing of DER systems and grid upgrade requirements.

SECTION 3

Evaluates the economic impacts of implementing the business model on Daystar, DisCos and the 20 pipeline customers. This section also discusses the financial impacts on Daystar, as well as modeling approach, assumptions, data inputs and results.

SECTION 4

Outlines the regulatory process for deployments of projects under the business model, including supporting documents needed for regulatory approval, major obligations for operating projects in accordance with regulations. The section also

discusses the problems faced during regulatory assessment, legal, regulatory and institutional challenges facing the business model, and proposed remedies and recommendations.

SECTION 5

Describes the design and scope of the tripartite agreement, summarizes key contract terms and considerations, as well as feedback and takeaways from preliminary contractual negotiation with DisCos and customers.

SECTION 6

Identifies U.S. suppliers that offer products or services relevant to the project. It includes a summary of the findings on US-Nigeria DER supply chain opportunities and challenges from interviewing US supplier representatives, and contact information of identified companies.

SECTION 7

Discusses the results of the preliminary environmental and social impact assessments which were conducted for 18 out of the 20 pipeline project locations.

SECTION 8

Assesses the developmental impact of the pipeline projects and for the business model at scale in terms of reduction in greenhouse gas (GHG) emissions, increase in installed renewable energy capacity in Nigeria.

SECTION 9

Lays out the key steps Daystar would have to take to successfully implement the 20 pipeline projects, which include an overview of key touch points with DisCos, a master timeline, procurement and financing consideration. Key risks and mitigation strategies and metrics for project evaluation are also discussed.

1.1 THE STUDY SCOPE

Under this grant, Daystar and RMI collaborated to scale a unique utility-enabled business model by de-risking 20 project sites across multiple DisCo territories. The feasibility study's terms of reference included 10 tasks:

TASK	DESCRIPTION
Task 1	Kick-Off Meeting and Information Gathering
Task 2	Technical Analysis and Utility Engagement
Task 3	Economic and Financial Analysis
Task 4	Regulatory Review
Task 5	Contract Development
Task 6	U.S. Sources of Supply Identification
Task 7	Preliminary Environmental and Social Impact Assessment
Task 8	Climate Change and Development Impact Assessment
Task 9	Implementation Plan
Task 10	Final Report

1.2 KICK-OFF MEETINGS AND INFORMATION GATHERING

RMI and Daystar held a virtual kickoff in November 2021 where the team aligned on requirements, expectations, key project management requirements and expected approaches to delivering the project. We later held in-person meetings in March 2022 to further agree on project approach, resulting in a preliminary workplan, as well as fruitful discussions on key modeling considerations, site criteria, and contract development requirements.

RMI and AEDC have maintained strong relationships for a number of years, and RMI initially engaged EKEDC during the grant development phase. RMI and Daystar met with AEDC and EKEDC during in-country visit in March 2022 to re-introduce the project and proposed business model. Both DisCos expressed strong interest in collaboration. We later engaged IE in summer 2022, who responded with enthusiasm as well.



Figure 1 In-person kickoff meeting between RMI and Daystar teams at Daystar's offices in Ikeja (9 March 2022)



Figure 2 RMI, Daystar, and EKEDC meet to discuss potential customers in the DisCo territory at EKEDC's office in Lagos (10 March 2022)

RMI developed an initial Data Information Request (DIR) form and submitted to Daystar who responded with a detailed technical and commercial information pertaining to DER solutions implemented by Daystar. Daystar also shared existing preliminary information on 18 potential project sites. This information included on details the customer type, load profile as well grid and backup power generation. Based on feedback from Daystar, RMI shortlisted sites to



explore. Further engagements with AEDC, EKEDC and IE grew the number of potential sites to evaluate. DisCos have also provided information requested such as feeder availability and customer tariff band.

After the kick-off meetings and based on data from DIR, RMI and Daystar developed and finalized a **Work Plan**, including a detailed activity list and schedule for the project. This Work Plan can be found in Annex 1-A of this report. Due to various constraints and delays caused by DisCo leadership and management changes, unstable market conditions and policy updates with new administration of Nigeria, and travel restrictions caused by the COVID-19 pandemic, the timeline in the Work Plan was adapted in collaboration with Daystar and USTDA a few times throughout the course of the project. RMI and Daystar worked collaboratively to update the project timelines, and RMI provided monthly status reports that kept USTDA and Daystar informed on the macro timeline of the project.



02

**TECHNICAL
ANALYSIS
AND UTILITY
ENGAGEMENT**

As part of the project de-risking efforts, RMI worked closely with Daystar and DisCos to shortlist suitable C&I customers, adapt the proposed business model, conduct site visits and gather customer data for load assessment and DER system design. We also worked with Afry, the network assessment consultant, to identify grid upgrade requirements to facilitate successful implementation of the business model. Ultimately, we developed 22 project sites to move on to subsequent stages of the feasibility study.



2.1 OVERVIEW OF THE PROPOSED BUSINESS MODEL AND ADAPTATION

KEY TAKEAWAYS

- The proposed utility-enabled business model can offer win-win-win for the customer, Daystar and DisCos, and is generally very well received. However, it is an innovative model that has never been implemented before with many aspects (such as how developer and DisCo collaborate effectively in project operations) to be field tested.
- Customers, Daystar and DisCos are aligned on the fundamental design of the business model, but the detailed arrangement can be further refined to meet specific needs. For example, the definition of DER technology and capacity, DisCo priority hours, and grid availability standards, etc.

2.1.1 BUSINESS MODEL OVERVIEW

The proposed utility-enabled business model will leverage the reliability benefits of distributed power, such as solar/batteries and the increased grid electricity consumption, to better serve C&I customers while replacing expensive diesel and gas self-generation. This model requires no upfront capital investment from the customer and Daystar,

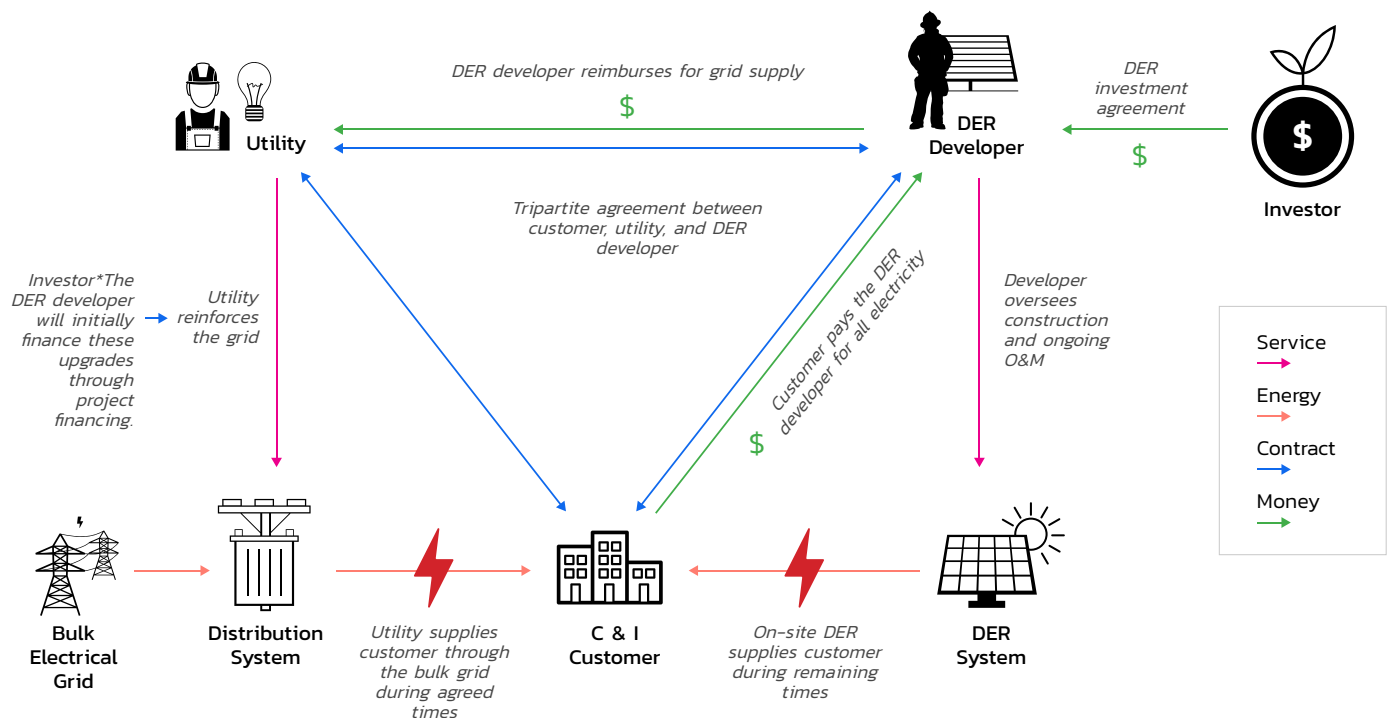
as the developer, is responsible for securing financing. The onsite DER system installed and operated by Daystar will provide power during daytime peak sun hours, while the expectation is that DisCos will increase grid hours of supply to provide energy in the evening, night, and early morning hours. Even during these hours, service

interruptions due to low supply from the grid can be lowered through the battery and generator backup, increasing reliability with a lower overall cost than a generator-only backup system. As needed, Daystar will finance grid upgrades to reduce DisCo aggregate technical and commercial losses and support improvement in electricity supply for the grid priority hours, generating more revenue for DisCo.

The customer, Daystar and DisCo will enter into a tripartite agreement. The customer will pay Daystar for all electricity consumed at a blended tariff,

which combines the price of electricity from the grid and the DER system. Daystar will then remit the grid portion of the revenue to DisCo, using the Multi Year Tariff Order (MYTO) tariffs. With this arrangement, Daystar will handle the billing and payment with the DisCo, while assuming the role of a bulk buyer (DisCo will meter grid consumption and issue utility bills to Daystar) and the customer's existing agreement with DisCo will be suspended over the duration of the tripartite agreement (i.e., customers don't need to pay the DisCo separately). Figure 3 below illustrates the business model.

Figure 3 Illustration of the proposed utility-enabled C&I business model





2.1.2 DETAILED DESIGN AND ADAPTATION CONSIDERATIONS

While the fundamentals of the business model (e.g., the roles and arrangement among the customer, DisCo and Daystar) will remain the same, the details can be adapted to meet the needs of specific customers and DisCos. Table 1 below summarizes consideration for key elements in the

business model design based on feedback from customer and DisCo engagement. We highlight adaptation for applicable customers in Section 2.5 in the report, and will discuss key contract terms in Section 5.

Table 2 Considerations for business model adaptation

ITEM	CONSIDERATIONS
Supply Hours	<p>The obligation to provide power to the customer will be shared between Daystar (as the DER developer) and the Disco. Below are the recommended and standard supply hours for Daystar and the DisCo. These hours can be agreed upon per transaction depending on the grid availability and commitment that the DisCo can make. A key principle is that DER Priority Hours should overlay with solar generating hours to maximize the DER utilization.</p> <ul style="list-style-type: none">• DER Priority Hours: 9:00 AM – 2:59 PM (for 6 hours)• Grid Priority Hours: 3:00 PM – 8:59 AM (for 8 hours) <p>This will affect the billing and financial settlement between Daystar and the DisCo, and might in the end affect the blended tariff offered to the customers.</p>
Back-up System	<p>Diesel generator is the default back-up system for most customers in our design, but some customers may prefer gas generation (and some already have existing gas power supply agreement). The choice of back-up system will affect the technical design of the DER system. Customer may also opt to integrate existing back-up system (if they meet the required performance standard) into the newly implemented DER system. In this case, Daystar will manage the onsite system as a whole and dispatch back-up when needed, but Daystar will not be responsible for procuring fuels.</p>
Grid Availability	<p>Daystar and DisCo will agree on the level of grid availability and reliability the DisCo can commit to for specific customer. Ideally the grid can offer 90% and above availability during the Grid Priority Hours.</p>

2.2 SUMMARY OF KEY DISCO ENGAGEMENT AND FEEDBACK

KEY TAKEAWAYS

- We had in-depth engagement with three DisCos and all expressed strong interest in the utility-enabled business model. DisCos see it as an opportunity to increase their revenues and improve customer satisfaction, especially as a solution to bring customers back to the grid.
- To incentivize DisCos to prioritize serving customers adopting this business model, we are designing a DisCo premium fee based on grid upgrade and DisCo operation costs, for the improved service.
- DisCo leadership change and staff turnover has been a major challenge over the course of the feasibility study. Future project de-risking and preparation need to be more streamlined and account for this risk factor (for example, to frontload as much as data collection and studies that require facility access and DisCo staff).
- Building and maintaining customer-developer-DisCo trust and relationship takes a lot of time and efforts. Developers and DisCos should view each other as partners in the endeavor. Once the business model and partnership are proven effective, it can unlock huge DER potentials across C&I sectors.

We engaged AEDC, EKEDC, and IE in this project. RMI team conducted in-country visits to formally introduce the business model and align on project design approach, and had regular virtual working sessions, discussions and consultations to finetune our analysis. Overall, the business model is well received by the DisCos, who expressed strong interest in pursuing project implementation. During the engagement, we identified a number of DisCos' key priorities, and the business model provides clear value add to support DisCos' goals.





Customer Acquisition:

Currently some C&I customers opt to stay off-grid or disconnect from the grid because grid supply cannot meet their needs. The proposed utility-enabled business model offers an alternative solution for DisCos to attract new customers, and encourage defected customers to come back to the grid.



Revenue Increase:

In addition to new revenue streams from new and returned customers, C&I customers can be charged a higher service-based tariff band with the increase in supply hours, increasing revenue streams for DisCos. DisCos will need to prioritize the feeder and the dispatch to ensure they meet their service obligation the customers in the C&I business model. All three DisCos suggested including a DisCo premium fee for the improved services. RMI and Daystar agreed that this is a reasonable incentive for DisCos to prioritize certain C&I customers, and we designed a premium fee structure based on grid upgrade and DisCo operation costs (which will be discussed in Task 3 report), further adding to DisCos' revenue. With such design, the premium fee will assist DisCos to repay the grid upgrade costs financed by the developer.



Customer Satisfaction and Retention:

Improve grid supply hours and reliability will prevent customer default to self-generation and improve customer satisfaction on DisCo services. Having a third party (Daystar/RMI) involved is often helpful in restoring and strengthening customer and DisCo relationship.



Scalability:

All three DisCos have a number of high-priority C&I customers that either have demanded solutions from DisCos, or DisCos wanted to improve the service with. The proposed business model would be suitable and attractive for some of these customers. Furthermore, DisCos are interested in further adapting the solutions from project implementation experiences and replicating it to offer more reliable power supply for customers in their territory.





In addition, the three DisCos each had some feedback reflecting their internal strategies and/or concerns around the business model. We continue to align closely with DisCos to support their priorities and address their concerns as we develop and ultimately implement the project pipeline.



The Disco is currently selecting feeders for franchises to reduce their aggregated technical commercial and collection (ATC&C) loss level at scale. There is a higher chance that feeders selected could have customers pre-selected for the C&I business model. Determining the best way to manage this and segment their coverage areas for various models will be part of their DER strategy.



There is a growing interest by management to focus more on franchise solutions due to various reasons; for example, the duration required to complete a C&I transaction could take over a year due to developers' execution capacity and customer engagement process. There is a higher outreach from developers wanting to develop solutions in clusters compared to a few years ago due to the recent regulation issued by the NERC.



The Disco had some concerns regarding guaranteeing a minimum supply hour based on a specific period and how the loss of revenue can be managed if the majority of the hours supplied by the Disco in the past were during the proposed hours for the DER. The Disco was very interested in working with RMI to determine the best way to resolve these concerns.



It's also worth noting that we encountered several challenges with DisCo engagement, which have caused delay of the feasibility study. When implementing the business model, these factors need to be carefully accounted for and planned around.



Weak grid infrastructure for certain customers:

Weak grid infrastructure for certain customers: Some shortlisted customers are located in areas where the grid infrastructure is insufficient or are connected to a very long feeder line. This means it would require significant grid infrastructure upgrades (beyond what Daystar is suited to finance) to meet the grid reliability in the proposed business model ideally calls for. We consulted DisCos and tried to incorporate various level of grid availability in the DER system design.



For future project development, Daystar can work with DisCo to evaluate and cluster potential C&I customers on the same feeder line, so there are more incentives for DisCo to conduct major grid upgrades.



Leadership change and staff turnover:

We experienced multiple leadership changes and staff turnover across all three DisCos. As a result, we lost momentum as we needed to re-introduce our project and business model, convince DisCos again and re-align the way forward, causing delays of the project. For example, AEDC had significant staff turnover in its DER division in September 2022 (this is addressed by funding a DER Officer position through another RMI project) and appointed a new CEO in August 2023. EKEDC had leadership change in early 2023 who set different

near-term priorities for project implementation, and we weren't able to gain traction since then. Building on the experience from this project, future project development process should be more streamlined while continuing building capacity of utility-enabled solutions and business models with DisCos.



Customer-Developer-DisCo trust building:

Implementing this innovative business model comes with new roles and responsibilities especially for developers and DisCos, who should view each other as partners and recognize the efforts they each need to make. In designing the tripartite terms, it's important to strike the balance of interests and protect them fairly (to be discussed in Task 5 reports).

2.3 SITE SELECTION OVERVIEW

KEY TAKEAWAYS

- Customers with high daytime energy demand and already showing grid defection are generally good fits for the business model.
- In engaging customers, we found that many customers are defecting from the grid due to poor reliability (to DER, diesel or gas) and see the value of improved grid supply coupled with onsite backups. Yet, customers don't always recognize that DERs can be viable alternative power solutions and many lack understanding of DER business models. Having successful implementation case studies would help educate and convince customers.
- We shortlisted a pipeline of 22 project sites and a list of 18 alternative sites, and had most success with sites originated by Daystar and IE (customers reached out to IE for support) in terms of pipeline conversion rate as cultivating new relationships with customers is not easy. Developing a customer-led process will be an important scaling lever.



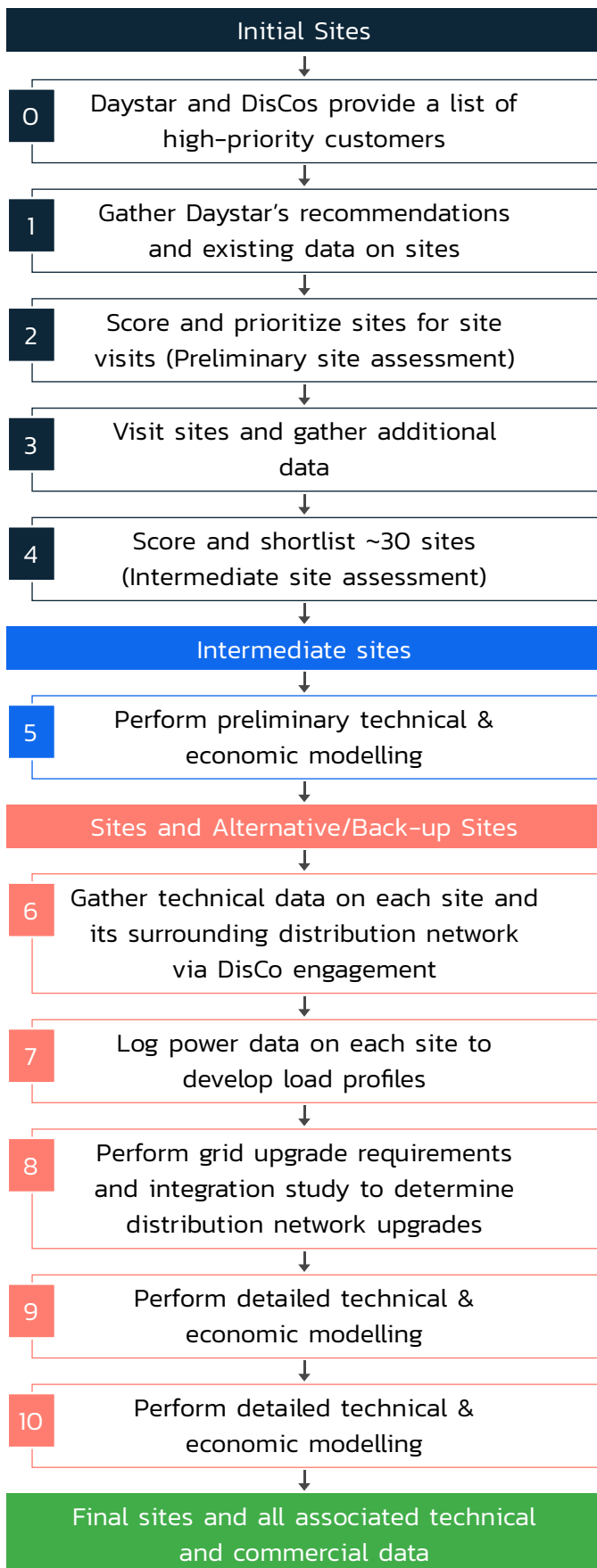
2.3.1 SITE SELECTION CRITERIA AND PROCESS

To identify the most suitable C&I sites with high potential for project implementation, we designed and followed a robust set of criteria and selection process. Table 3 introduces the preferred customer characteristics, and Figure 4 shows an overview of the site evaluation and selection process.

Table 3 Preferred customer characteristics

	CRITERIA	PREFERRED CUSTOMER CHARACTERISTICS
very Important	Current grid hours of supply	Customer preferably receives less than 12–14 hours of daily electricity supply from the grid
	Significant daytime electricity use & evidence of partial grid defection	Customer uses a diesel generator rated at 60 kW (75 kVA) or higher
	Physical appropriateness of site for DERs	Customer has a minimum of ~500m ² in available rooftop and land space for PV installation
	Customer interest	Customer shows enthusiasm for a DER solution and is willing to sign a long-term contract
Important	Ease of customer engagement and data collection	Customer has data available or allows for easy data collection
	Implementation period	Customer has a simplified decision-making structure that would shorten project timeline; customer might have sustainability goals that encourage action
	Customer grouping dynamics	Customer is closely located around other large C&I customers

Figure 4 Site evaluation and selection process



Sites are evaluated and scored against the criteria listed in the Table 4 below. For each criterion, a site scores from 1(Low) to 3 (High) and a weighted average is calculated based on the criterion weight. Sites with a weighted average score greater than 2 are considered a 'high' fit for this business model (BM Fit), between 1 and 1.5 are considered a 'medium' fit, and less than 1.5 are considered a 'low' fit for this business model.





Table 4 Preliminary site selection criteria

CRITERION	HIGH (SCORE 3)	MID (SCORE 2)	LOW (SCORE 1)	WEIGHT
Current grid hours of supply (grid reliability)	Customer receives 0 – 8 hours of daily electricity supply from the grid	Customer receives 8 – 14 hours of daily electricity supply from the grid	Customer receives 14+ hours of daily electricity supply from the grid	2
High electricity demand	Customer peak load is greater than 60kW	Customer peak load is between 40kW and 60kW	Customer peak load is between 24kW and 40kW	2
Significant daytime electricity use	Customer's peak load is between 9am to 4pm (solar generating hours) and operating hours is between 6am to 7pm with minimal operation outside these hours	Customer's peak load is between 9am to 4pm but customer has significant operations at night (7pm – 6am)	Customer's peak load is not between 9am to 4pm and customer has significant operations at night (7pm – 6am)	2
Evidence of partial grid defection	Customer uses a diesel generator for > 6 hours per day	Customer uses a diesel generator for 3 – 6 hours per day	Customer uses a diesel generator for less than 3 hours per day	2
Physical appropriateness of site for DERs	Customer has a greater than 10m ² /kW (peak load) in available rooftop and land space for PV installation ⁱⁱⁱ	Customer has a greater between 6m ² /kW to 10m ² /kW (peak load) in available rooftop and land space for PV installation	Customer has between than 4m ² /kW to 6m ² /kW (peak load) in available rooftop and land space for PV installation	2
Ease of grid integration	Customer is connected to a 33kV connection, or a dedicated 11kV connection	Customer is not connected to a 33kV connection, or a dedicated 11kV connection but is connected at 11kV or is within a cluster (same feeder or same injection substation) of 3+ customers actively being considered for the business model	Customer is connected at 415V level and is not in a cluster of 3+ customers actively considered for the business model	2
Customer Impression of DisCO-enabled business model	Customer understands DisCO role, benefits of DisCO-enabled solution and has a positive impression of the DisCO	Customer has a neutral confidence in Disco ability and has a neutral impression of the DisCO	Customer has low confidence in Disco ability and has a negative impression of the DisCO	1

ⁱⁱⁱ For example, if the peak load is 100kW, the customer would score "High" if there is more than 1,000 m² of space available.

CRITERION	HIGH (SCORE 3)	MID (SCORE 2)	LOW (SCORE 1)	WEIGHT
Customer interest	Customer shows high enthusiasm for a DER solution and is willing to sign a long-term contract.	Customer shows some enthusiasm for a DER solution and/or is willing to sign a long-term contract	Customer shows little enthusiasm for a DER solution and/or is not willing to sign a long-term contract	1
Ease of customer engagement and data collection	Customer has data available or allows for easy data collection	Customer can make data available upon request	Customer is unwilling to provide necessary data	1
Implementation period	Customer has a simplified decision-making structure that would shorten project timeline and sustainability goals that encourage action	Customer has a simplified decision-making structure that would shorten project timeline; customer might not have sustainability goals that encourage action	Customer has a complicated decision-making structure that would shorten project timeline; customer might not have sustainability goals that encourage action	1

2.3.2 SITE VISITS AND CUSTOMER ENGAGEMENT PLAN

A key step in the customer selection process is to conduct visits to customer sites and engage customers in person (Step 3 in Figure 4). The goal of each site visit is to understand the electricity needs of the customer and to collect foundational information required to determine whether the facility is appropriate for the utility-enabled C&I business model against our site selection criteria. During the site visits, RMI and Daystar presented the project and proposed business model to the customers, toured the facilities and collected customer feedback and data. Table 4 below summarizes key discussion topics with customers during the site visit and follow-up engagements, and these inputs fed directly into the site evaluation. A template form for customer data collection is included in Annex 2–A.





Table 5 Key customer discussion topics during site visit

S/N	TOPIC	OBJECTIVES AND KEY QUESTIONS
1	Current grid hours of supply	Understand the current level of customer supply—what percentage of their electricity do they get from grid? Are their electric bills accurate? What rate do they pay?
2	Electricity demand	Understand customer electricity demand, their main end-uses of energy (e.g., motors, HVAC, lighting, etc.), how they expect those uses to change (e.g., planned expansion, energy efficiency upgrades, etc.). What is customer peak load? Where are the energy efficiency opportunities? Understand impact of COVID on their business and whether they've resumed business operations at full capacity. Does the customer expect the elections to impact their operations at all? Do they have any other political and macroeconomic concerns?
3	Significant daytime electricity use	Understand the hours of operation and the daytime power demand. Understand daily/weekly/seasonal fluctuations (e.g., does their output slow during the rainy season, etc.).
4	Evidence of partial grid defection	Understand generator operating conditions including frequency of usage and amount of diesel fuel consumed (note size & number of customers' generators). Is diesel purchase a significant cost item and pain point? Understand who operates the genset (e.g., is it contracted out), how new it is, how often they have issues with it starting/failing, whether they have long-term fuel supply contracts.
5	Physical appropriateness of site for DERs	Assess the availability of space for an on-site DER solution. How much rooftop and land space for PV installation is available? Does the customer have any restrictions or limitations regarding rooftop and ground access? Does the customer's roof have any load-bearing limitations?
6	Impression of DisCo	Assess the customer's impression of the DisCo. How satisfied have they been with the DisCo in the past outside of the frequency of power supply? What is their level of confidence in the DisCo's general ability? Affirm the customer's understanding of the DisCo involvement in the business model.
7	Customer interest	Affirm the example customer's service improvement needs are in line with the value proposition of the business model. Understand the decision drivers for the customer/key decision-makers of the customer company? Assess the customer's willingness to understand the full energy cost of their facility, and offset diesel costs with increased electricity and reliability; understand if the customer is open to paying any upfront costs for the solution. Understand any specific power needs or any nuance to their power needs we may not be aware of.
8	Ease of customer engagement and data collection	Understand the communication preference of the customer, and if they would be open to communication with RMI directly. How much data does the customer have available on facility load profile, diesel consumption? Does the customer have a responsive contact person to communicate with? For example, a facility manager or utility manager?

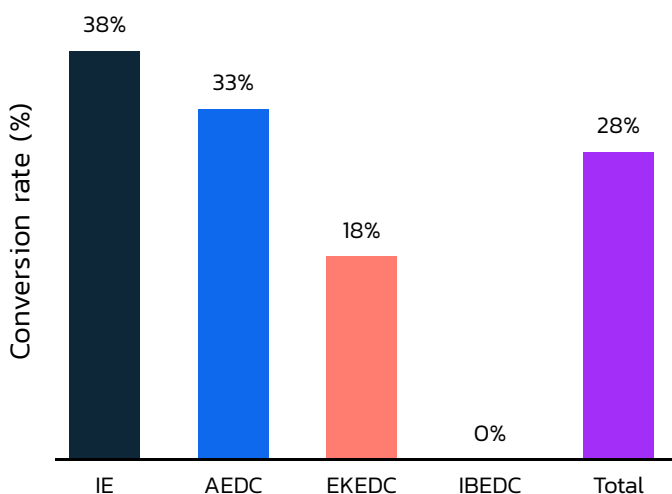
S/N	TOPIC	OBJECTIVES AND KEY QUESTIONS
9	Implementation period	Understand customer's decision-making structure. Would it help shorten the project timeline? Does the customer have sustainability goals that encourage quick action?
10	Ease of grid Integration	Assess features including – customer connection voltage, level of existing electrical isolation, customer clustering and customer quality of grid service.
11	General risks & concerns	Understand if the customer has any concerns regarding solution deployment, communication process and next steps. Discuss any implementation concerns. Are there any risks that the customer is worried about regarding the business model and potential project? Explain that we would follow up with DisCo engagement and can get information that addresses DisCo related concerns.

2.3.3 SHORTLISTED SITES

We evaluated a total of 82 sites, conducted 41 site visits and after numerous rounds of engagement with customers and DisCos, we identified 22 sites to include in the pipeline for the feasibility study. Figure 3 below shows the conversion rate of the site selection. Among the 22 sites, 12 are in AEDC, five are in EKEDC and five are in IE. The list of selected sites is included in Table 6. More information and technical analysis results of these sites will be presented in Section 2.5 of the report.

Figure 5 Site conversion rate from sites evaluated to sites included in the pipeline

CONVERSION RATE ON CONSIDERED SITES BY DISCO TERRITORY



CONVERSION RATE ON CONSIDERED SITES BY ORIGINATOR

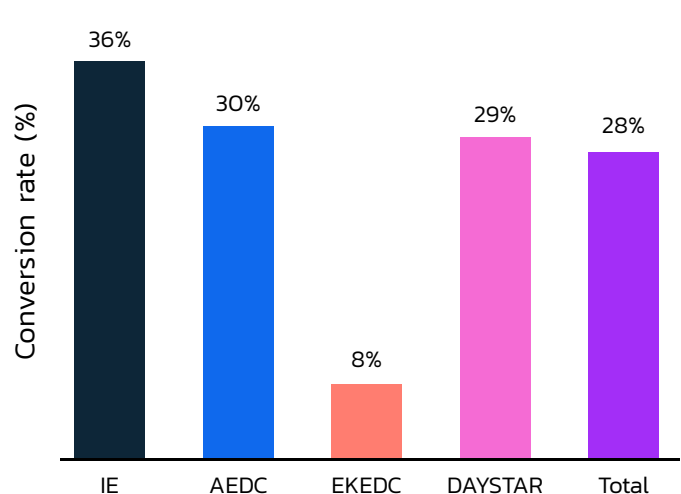




Table 6 List of selected sites

NO.	NAME OF CUSTOMER ^{iv}	DISCO
1	[Customer 1]	AEDC
2	[Customer 2]	AEDC
3	[Customer 3]	AEDC
4	[Customer 4]	AEDC
5	[Customer 5]	AEDC
6	[Customer 6]	AEDC
7	[Customer 7]	AEDC
8	[Customer 8]	AEDC
9	[Customer 9]	AEDC
10	[Customer 10]	AEDC
11	[Customer 11]	AEDC
12	[Customer 12]	AEDC
13	[Customer 13]	IE
14	[Customer 14]	IE
15	[Customer 15]	IE
16	[Customer 16]	IE
17	[Customer 17]	EKEDC
18	[Customer 18]	EKEDC
19	[Customer 19]	EKEDC
20	[Customer 20]	EKEDC
21	[Customer 21]	EKEDC
22	[Customer 22]	EKEDC

2.3.4 ALTERNATE SITES

The team also identified 18 customers as backup sites (see Table 7). These sites have some preferred characteristics, some even scored “high” BM Fit when evaluating against the site selection criteria. However, many of them are less engaging (e.g., willing to share or allow us log energy data) and have complicated internal decision-making structures that prevented us from pursuing these sites within the project timeline. Still, they have potentials to be upgraded to future pipeline for de-risking and project preparation.

^{iv} Here, customers are listed by DisCo, so the numbering is different from the first table in the Executive Summary. Later customer numbering is consistent with Table 6 here, except for Table 27 in Section 3, which is the same as in Table ESI.



Table 7 List of alternate sites

NO.	NAME OF CUSTOMER	DISCO
1	[Customer A]	AEDC
2	[Customer B]	AEDC
3	[Customer C]	AEDC
4	[Customer D]	AEDC
5	[Customer E]	AEDC
6	[Customer F]	AEDC
7	[Customer G]	AEDC
8	[Customer H]	AEDC
9	[Customer I]	AEDC
10	[Customer J]	AEDC
11	[Customer K]	AEDC
12	[Customer L]	AEDC
13	[Customer M]	AEDC
14	[Customer N]	IE
15	[Customer O]	IE
16	[CustomerP]	IE
17	[Customer Q]	EKEDC
18	[Customer R]	EKEDC

2.4 TECHNICAL ANALYSIS METHODOLOGY

KEY TAKEAWAYS

- Data availability and quality are common challenges when evaluating customers. Most customers don't have measured consumption data or good documentation of energy expenditures. We had to install data loggers and sometimes re-log some sites (e.g., in cases where there were separate power connections for grid and multiple generators, and the site was inadequately logged). The lengthy data collection process has led to some project delay. Going forward, project development team should build ample time for gathering customer data.
- It's important to align modeling scenarios with Daystar Engineer and Project teams and bring them to understand the proposed business model. This is to avoid reverting to business-as-usual design process and not accounting for DisCo collaboration later on.
- DisCos need to be involved and consulted throughout the distribution network assessment, and note that data scarcity is a common issue across DisCos.



2.4.1 LOAD ASSESSMENT

RMI and Daystar installed data loggers onsite to measure the load of each customer, unless Daystar or the customers already had metered consumption data of such granularity. For the majority of sites, we obtained at least one month of load data. With logged demand data, we developed average daily load profiles to illustrate the consumption pattern in a “typical” week for the customer. Based on the daily load profiles, we extrapolated the “typical” week to estimate the 8760hr annual electricity usage. The 8760 load profile is later imported into HOMER Pro for DER sizing and dispatch simulation.

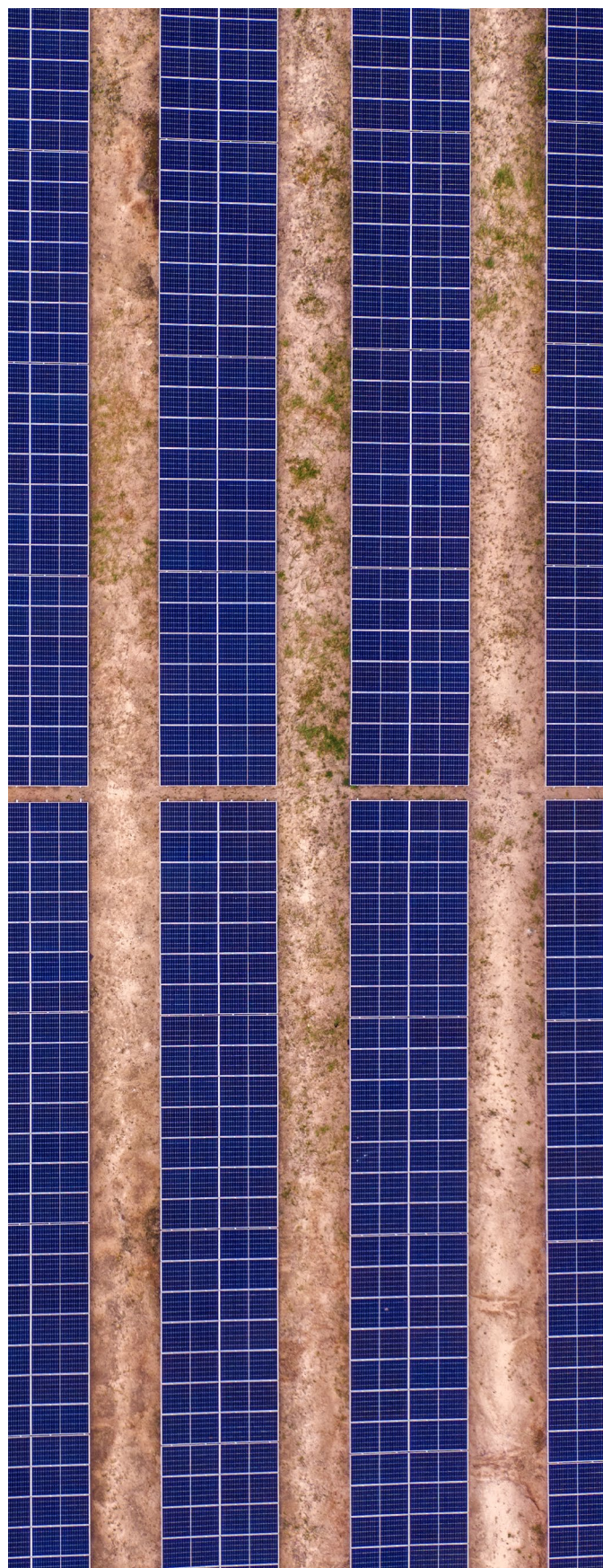
2.4.2 TECHNOLOGY CHOICES AND SIZING OF DER SYSTEM

Solar-battery-diesel hybrid DER system has been proven cost-effective to provide affordable and reliable power to end users. In our design, the preferred technology choices for the DER system are solar PV, li-ion battery storage (for its higher efficiency and longer lifespan compared to other battery technology) and diesel generator as backup. Gas generator requires a higher capital expenditure (CAPEX) and lower operating and fuel cost, so it could also be a viable and sometimes preferred option for customers with larger consumption and/or access to gas infrastructure, to justify the high upfront costs.

As part of the DER solution, Daystar plans to install smart inverters, which have the capability to control power voltage and frequency for the end-users, resolving potential power quality issues that some customers are experiencing. Daystar’s Engineering Team can work with customers to properly set the range.

RMI team and Daystar had several rounds of working sessions to align on the modeling approach. We used HOMER Pro to size the DER system and simulate the hourly dispatch from the DER system and grid to serve customer loads. The main driving factors in system sizing are cost-effectiveness and reliability, and we followed the methodology and

steps as aligned with Daystar team. Key technical design assumptions are summarized in Table 8.



1. Firstly, we import load during DER Priority Hours (9am–3pm in our analysis) into HOMER and have HOMER optimize the solar sizing, while using pre-sized battery and genset to ensure high reliability (95% reliability for the DER system).
 - a. Battery is pre-sized to be able to power the average daytime load for two hours.
 - b. Genset and battery converter need to each be able to power peak load. For example, if the peak load is 100 kW, then the genset and battery converter should be pre-sized to be 100 kW.
 - c. Solar PV should be placed on the AC bus in HOMER design.
 - d. Solar PV inverter is sized with DC:AC ratio of 1.25.
 - e. Customer's available physical space (rooftop, carport) can be a constraint for the optimal solar sizing. We assume 70% of the total available space can be used for solar installations, and 1 kW panel will need about 4.67 square meters of space.
2. With the DER component sized, we then import 8760 load profile into HOMER, and add grid component into the system design to simulate hourly dispatch. Grid availability is also incorporated in the simulation.
 - a. To reflect 90% grid availability during Grid Priority Hours, (i.e., 1.8 hours outage on average), we scheduled random outages in HOMER 365 times per year, averaging 1.8 hours each time.
 - b. To reflect 75% grid availability during Grid Priority Hours, (i.e., 4.5 hours outage on average), we scheduled random outages in HOMER 365 times per year, averaging 4.5 hours each time.
 - c. To reflect 50% grid availability during Grid Priority Hours, (i.e., 9 hours outage on average), we scheduled random outages in HOMER 730 times per year, averaging 4.5 hours each time.





Table 8 Key technical modeling assumptions

MINIGRID HARDWARE COSTS (FOR HOMER MODELING)		
Solar CAPEX	[REDACTED]	Includes panel, mounting structure, installation, balance of system. From prior discussion with Daystar (The panel itself is [REDACTED])
Solar lifespan	20 years	RMI and Daystar observed industry data
Battery CAPEX (Lithium-ion)	[REDACTED]	From prior discussion with Daystar and recent procurement data shared by Daystar. This includes battery converter cost as supplier usually quote the package.
Battery lifespan (Lithium-ion)	10 years	RMI and Daystar observed industry data
Diesel CAPEX	[REDACTED]	From prior discussion with Daystar and recent procurement data shared by Daystar.
Diesel lifespan	[REDACTED]	From prior discussion with Daystar
Diesel fuel	[REDACTED]	From prior discussion with Daystar. Note that this is higher than recent market prices to discourage HOMER to dispatch diesel, as one of the goals is to minimize diesel consumption.
Inverter CAPEX	[REDACTED]	From prior discussion with Daystar
Converter lifespan	15 years	HOMER default
System Operational Constrains and Grid Reliability Sensitivity		
Diesel minimum operating capacity	25%	HOMER default
Solar output as operating reserve	0%	RMI assumption
Grid reliability	Varies	Depending on grid availability reported by the DisCos for specific sites, which will be reflected in number and frequency of outages in HOMER

The system design and sizing can be further finetuned based on customer preference and feedback, and available procurement options in the market. For example, customers may be comfortable with a lower reliability target or consider integrating existing diesel genset instead of Daystar investing in a new backup genset, to lower the cost of the system and resulting customer tariff. To do that, we would re-run the HOMER simulations to confirm technical feasibility and update related outputs for financial analysis.



2.4.3 GRID UPGRADE REQUIREMENTS STUDY

We worked with Afry, the network assessment consultant, to carry out field study to identify and recommend necessary distribution network upgrades to facilitate the business model (ensuring DisCos can meet their availability standards). The field assessment was conducted in close coordination with DisCo technicians to evaluate the conditions of the transformer and feeder line the customer is connected to, and other major power equipment at the customer's premises. Afry then made recommendations on grid upgrade items and estimated the equipment

and installation costs based on vendor quotes.

The Afry team completed network assessments for a total of 22 customers, 20 of which ended up in the current 22-site pipeline.^v Due to challenge with EKEDC engagement since their leadership change in early 2023, we were unable to carry out grid upgrade study for two EKEDC customers—[REDACTED] Grid upgrade requirements for each customer are summarized in Section 6 and [REDACTED]

2.5 SITE-SPECIFIC TECHNICAL ANALYSIS RESULTS

This section discusses the evaluation and technical analysis of each of the 22 sites in the pipeline, including load assessment, sizing of DER systems, and grid upgrade requirements (see summary table below).

Table 9 Summary of assessment and technical analysis of pipeline sites

CUSTOMER	BM FIT	LOAD	SYSTEM SIZING			GRID UPGRADE REQUIRED
			SOLAR	BATTERY	DIESEL/ GAS	
[Customer 1]	High	Peak: 250kW Ave: 200kW	594 kW	600 kWh	N/A	Upgrades of customer meter and connection; replacement of damaged component on feeder
[Customer 2]	High	Peak: 200kW Ave:120kW	321 kW	235 kWh	210 kW	Replacement of damaged component on feeder
[Customer 3]	High	Peak: 230kW Ave:180kW	621 kW	362 kWh	230 kW	Replacement of damaged component on feeder
[Customer 4]	High	Peak: 77Kw Ave: 38kW	103 kW	77 kWh	77 kW	Replacement of damaged component on feeder
[Customer 5]	Med	Peak: 54kW Ave: 23kW	106 kW	45 kWh	54 kW	Replacement of damaged cross-arm on feeder
[Customer 6]	High	Peak: 160kW Ave: 124kW	350 kW	247 kWh	165 kW	Replacement of damaged cross-arm on feeder

^v Network assessment was done for Customer A and Customer Q which are later deprioritized and removed from the pipeline project sites. They are among the Alternate Sites now.



CUSTOMER	BM FIT	LOAD	SYSTEM SIZING			GRID UPGRADE REQUIRED
			SOLAR	BATTERY	DIESEL/ GAS	
[Customer 7]	High	Peak: 590kW Ave: 295kW	450 kW	592 kWh	591 kW	Replacement of damaged component on feeder
[Customer 8]	High	Peak: 90kW Ave: 22kW	113 kW	44 kWh	93 kW	(Same as Serdir Plastics above)
[Customer 9]	High	Peak: 3MW Ave: 1.8MW	5,003 kW	3,730 kWh	3,000 kW	N/A (Control vegetation along feeder as routine maintenance)
[Customer 10]	High	Peak: 1.7MW Ave: 1.1MW	3,001 kW	2,265 kWh	1,700 kW	Replacement of damaged component on feeder
[Customer 11]	High	Peak: 345kW Ave: 260kW	802 kW	515 kWh	345 kW	Upgrade of customer transformer, replacement of damaged component on feeder
[Customer 12]	High	Peak: 200kW Ave: 150kW	489 kW	300 kWh	206 kW	Replacement of damaged component on feeder
[Customer 13]	High	Peak: 3.5MW Ave: 1.8 MW	4,500 kW	3,724 kWh	N/A	N/A (No upgrades needed)
[Customer 14]	Med	Peak: 380kW Ave: 80kW	513 kW	162 kWh	396 kW	Replacement of damaged poles on feeder
[Customer 15]	High	Peak: 170kW Ave: 90kW	385 kW	182 kWh	172 kW	Replacement of damaged crossarm on feeder
[Customer 16]	High	Peak: 5.8MW Ave: 3.1MW	7,973 kW	6,219 kWh	N/A	Extending feeder line to connect customer to grid
[Customer 17]	High	Peak: 50kW Ave: 32kW	75 kW	64 kWh	68 kW	Replacement of damaged
[Customer 18]	High	Peak: 160kW Ave: 135kW	135 kW	270 kWh	164 kW	N/A (Need to conduct assessment)
[Customer 19]	High	Peak: 600kW Ave: 410kW	1,521kW	816 kWh	617 kW	N/A (Need to conduct assessment)
[Customer 20]	High	Peak: 250kW Ave: 145kW	559 kW	146 kWh	257 kW	Maintenance on feeder, such as tighten guy wires and reinforce poles
[Customer 21]	High	Peak: 80kW Ave: 37kW	50 kW	75 kWh	80 kW	Replacement of damaged component on feeder
[Customer 22]	High	Peak: 390kW Ave: 290kW	1,007 kW	583 kWh	395 kW	Repair of leaning poles, replacement of damaged component on feeder

2.5.1 CUSTOMER 1

Customer 1 is a furniture manufacturer located in the Idu Industrial District in Abuja, manufacturing furniture pieces, doors, etc. The Customer is currently completely defected from the grid and use diesel generator onsite to power all its business operations. The site shows high daytime energy demand with a peak demand of 250 kW, and an average demand of 200 kW. The factory is physically appropriate for Solar PV installations with 5,000 m² of available rooftop space makes a great candidate for the business model (rated "High" BM Fit in our evaluation), and deploying the utility-enabled DER solutions can help the factory

access reliable power supply and reduce diesel cost.

The average daily load profile and system design for Customer 1 are shown below. The customer has requested us to incorporate its existing diesel generator into the onsite DER system as backup, hence we did not include a new diesel genset in our design. The customer is most ready for immediate implementation, so the design also incorporated battery specification and configuration currently available in the market.

Figure 6 Average daily load profile and system design for Customer 1

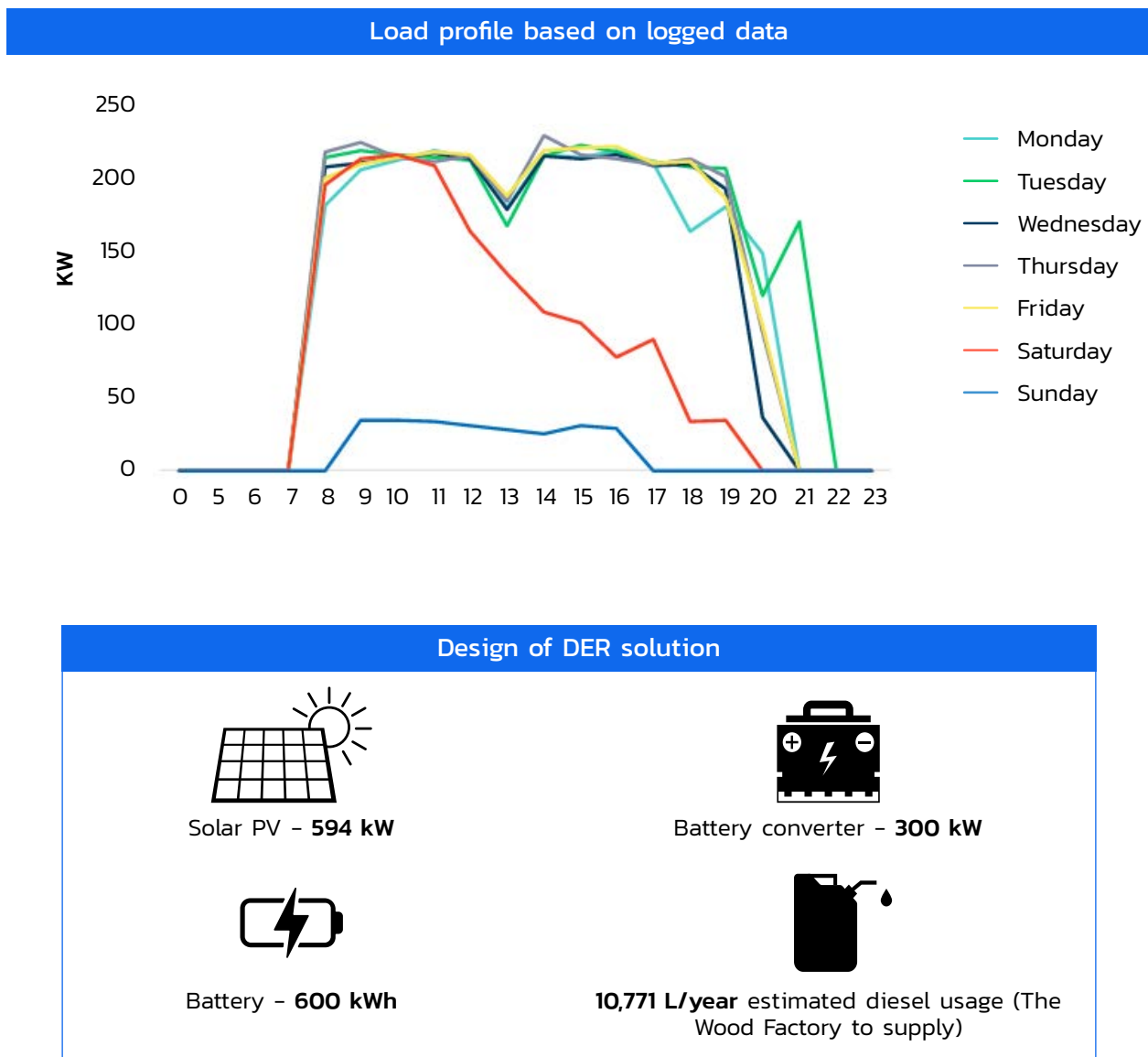




Table 10 below outlines the critical grid upgrades that the RMI, Daystar, and AEDC teams have jointly agreed upon as the top priorities for Customer 1, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 10 Grid upgrade recommendations for Customer 1

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of four damaged cross-arms along feeder	[REDACTED]
Replacement of four sets of stay wires along feeder	[REDACTED]
Five Raychem termination kit	[REDACTED]
Replacement of armoured cable, cable lugs and copper bar	[REDACTED]
Installation of a new LV meter for DC	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

2.5.2 CUSTOMER 2

Customer 2 is a manufacturer of exercise books located in Idu Industrial District in Abuja. The customer operates its business year-round, and our analysis of Customer 2 power consumption data suggests high daytime peak energy demand of 200 kW, and an average demand of 120 kW. Currently, the site only receives about six hours of grid supply daily, showing significant grid defection and can benefit from DERs to reduce

diesel backup generation, save energy cost and improve reliability. The facility has about 7,000 m² rooftop space and 3,000 m² carport space available, sufficient to install the optimal sizing of solar panels. Customer 2 scored highly against our site selection criteria and has high potential to implement utility-enabled DER solution. The average daily load profile and system design for Customer 2 are shown below.

Figure 7 Average daily load profile and system design for Customer 2

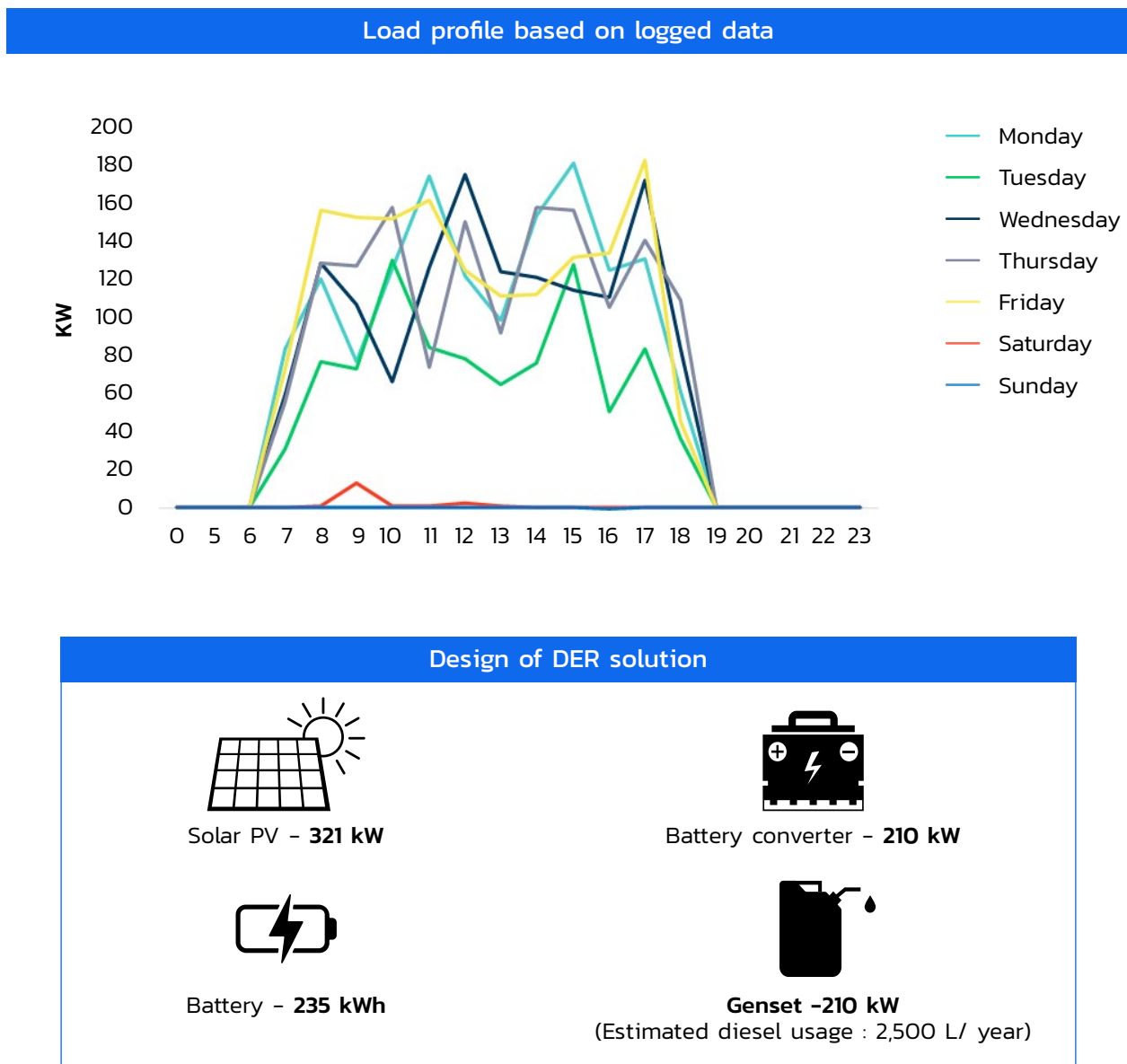


Table 11 below outlines the critical grid upgrades that the RMI, Daystar, and AEDC teams have jointly agreed upon as the top priorities for Customer 2, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 11 Grid upgrade recommendations for Customer 2

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of four damaged cross-arms along feeder	[REDACTED]
Replacement of three pairs of tie straps along feeder	[REDACTED]
Replacement of three sets of stay wires along feeder	[REDACTED]
Miscellaneous (20% of equipment cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

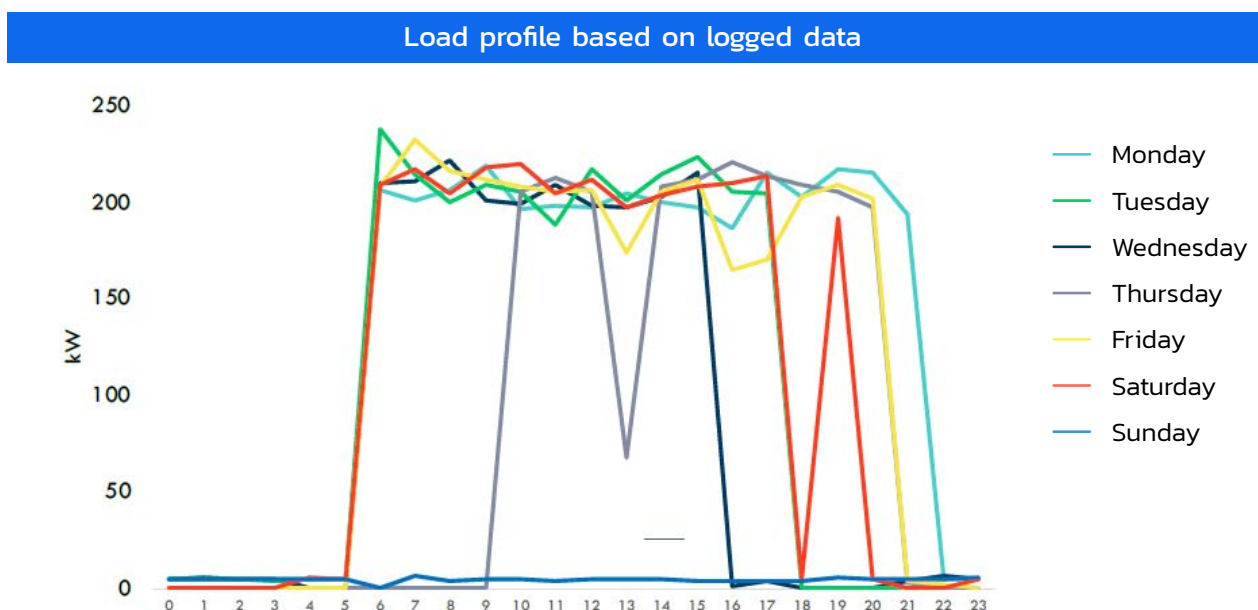
2.5.3 CUSTOMER 3

Customer 3 is a gypsum processing plant in Abuja. Our analysis of Customer 3 power consumption data suggests high daytime peak energy demand of 230 kW, and an average demand of 180 kW. Currently, the site receives about eight hours of supply from the grid and relies on diesel backup generator for remaining hours. Diesel cost is a major pain point for the customer, and they

are eager for alternative solutions. The facility has about 8,000 m² space available for solar installation, sufficient for the optimal solar sizing. With these characteristics, Customer 3 makes a good candidate for the proposed business model.

The average daily load profile and system design for Customer 3 are shown below.

Figure 8 Average daily load profile and system design for Customer 3



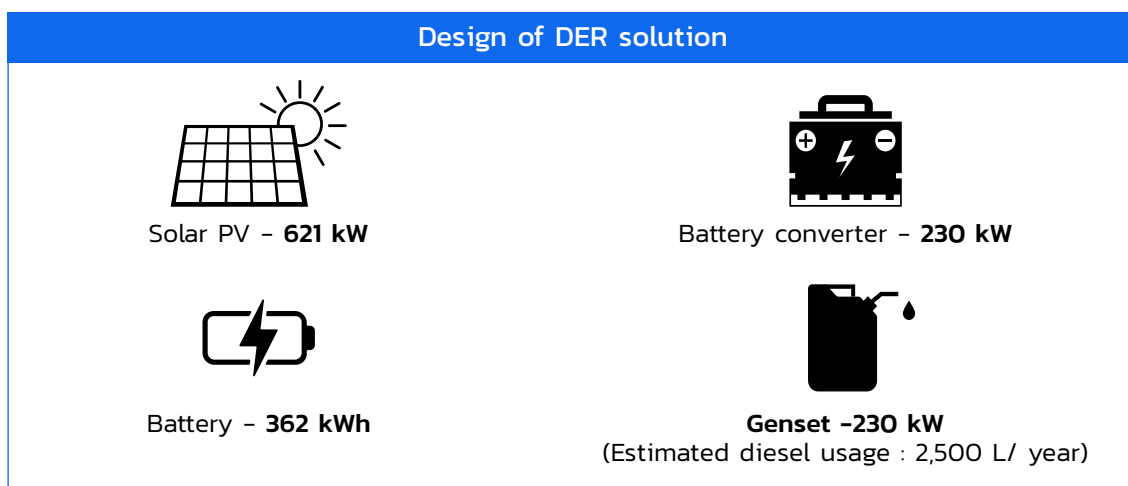


Table 12 below outlines the critical grid upgrades that the RMI, Daystar, and AEDC teams have jointly agreed upon as the top priorities for Customer 3 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 12 Grid upgrade recommendations for Customer 3

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Installation of one gang isolator switch	[REDACTED]
Replacement of one damaged cross-arms along feeder	[REDACTED]
Replacement of two cracked concrete poles	[REDACTED]
Replacement of 16 sets of vandalized stay wires on feeder	[REDACTED]
Reinforcement of one pole foundation	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

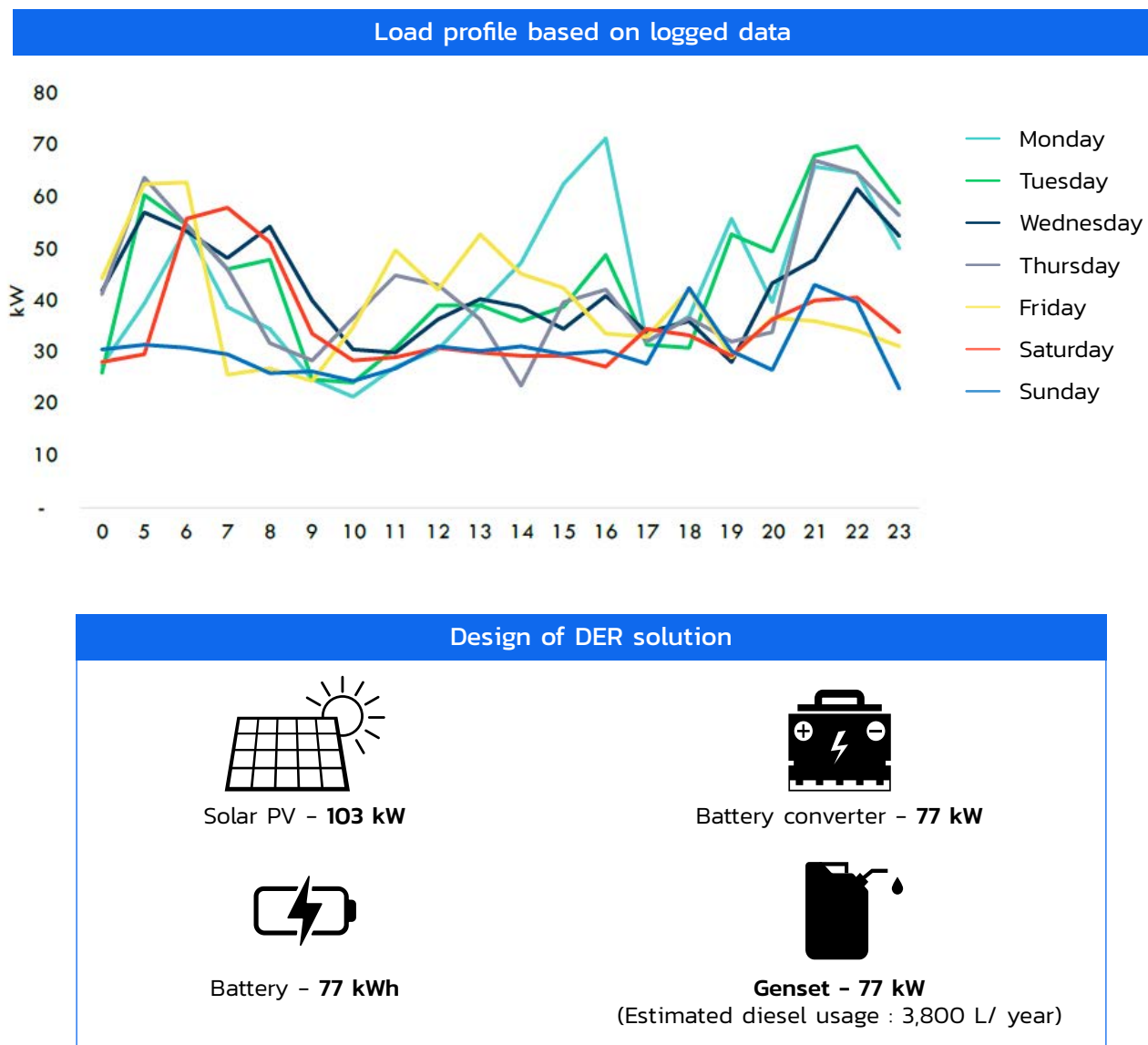
2.5.4 CUSTOMER 4

Customer 4, established in 2013, is a premier day and boarding secondary school in Abuja. Our analysis of Customer 4 power consumption data suggests high daytime peak energy demand of 77 kW, and an average demand of 38 kW. Currently, due to unreliable and insufficient grid supply, Customer 4 uses multiple diesel generator units for backup. Customer 4 is physically appropriate for

solar DER installations with more than 15,000 m² of rooftop and ground space available. Deploying utility-enabled DER solutions can help the facility access reliable supply and save on energy costs.

The average daily load profile and system design for Customer 4 are shown below.

Figure 9 Average daily load profile and system design for Customer 4



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 4, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 13 Grid upgrade recommendations for Customer 4

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of four damaged cross-arms along feeder	[REDACTED]
Replacement of one pair of tie straps along feeder	[REDACTED]
Replacement of two sets of stay wires along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

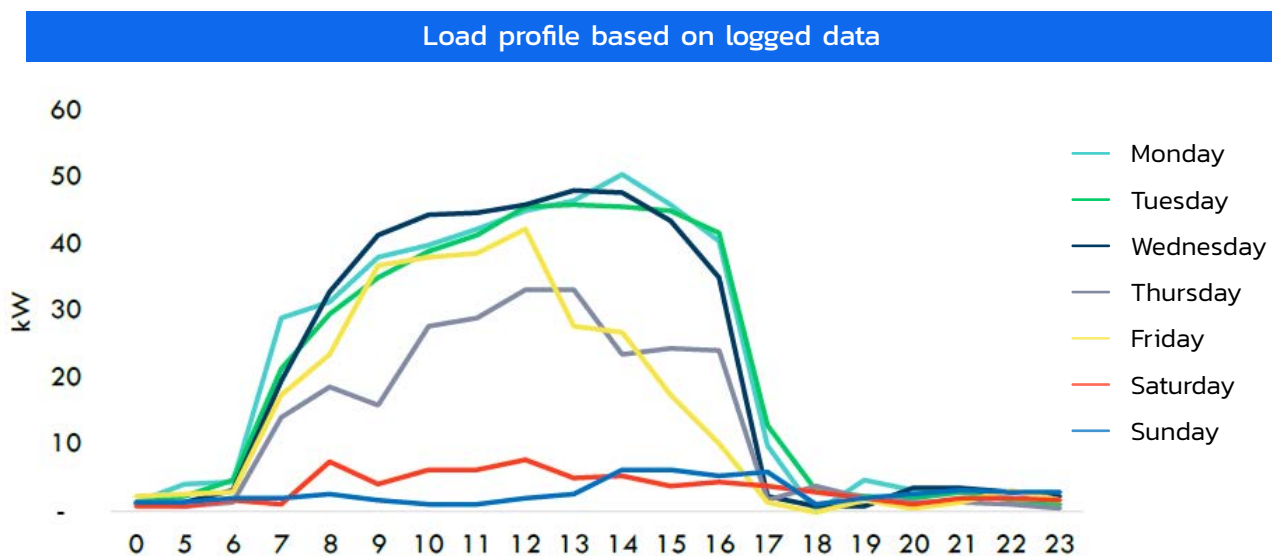
2.5.5 CUSTOMER 5

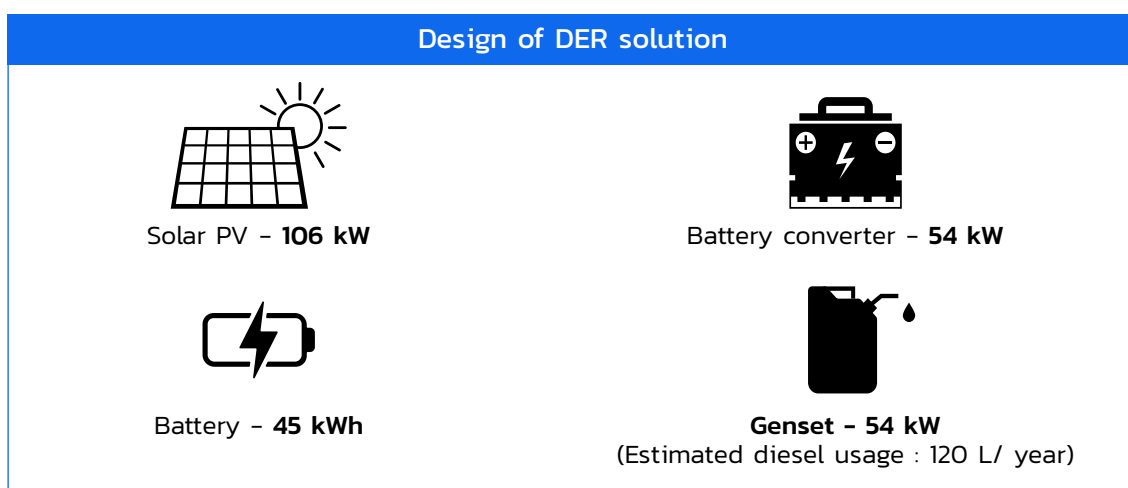
Customer 5 is a private day and boarding coeducational school that provides for Early Years to Year 12. Our analysis of Customer 5 power consumption data suggests high daytime peak energy demand of 54 kW, and an average demand of 23 kW. With unreliable grid supply, the school resorts to self-generation. With increasing fuel prices, Customer 5 has implemented some energy efficiency measures (e.g., turning off all devices at night) to reduce their energy consumption. The school campus is physically appropriate for

solar DER installations with about 5,000 m² of rooftop and ground space available. The proposed utility-enabled DER solution offers the school an opportunity to access reliable power supply and save on energy costs, while restoring and strengthening relationship with AEDC (as they reported sending several complaints to AEDC already).

The average daily load profile and system design for Customer 5 are shown below.

Figure 10 Average daily load profile and system design for Customer 5





The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 5 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 14 Grid upgrade recommendations for Customer 5

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of two damaged cross-arms along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

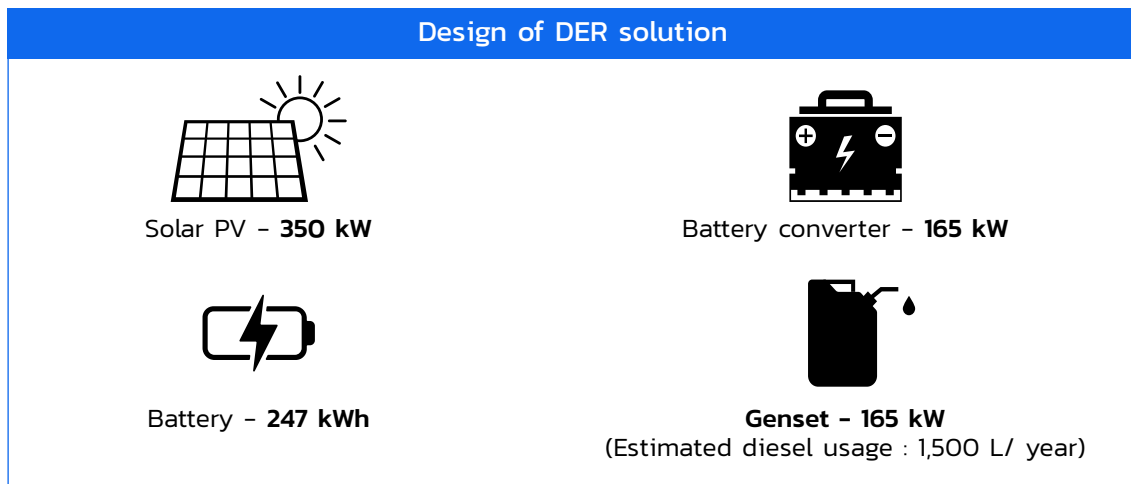
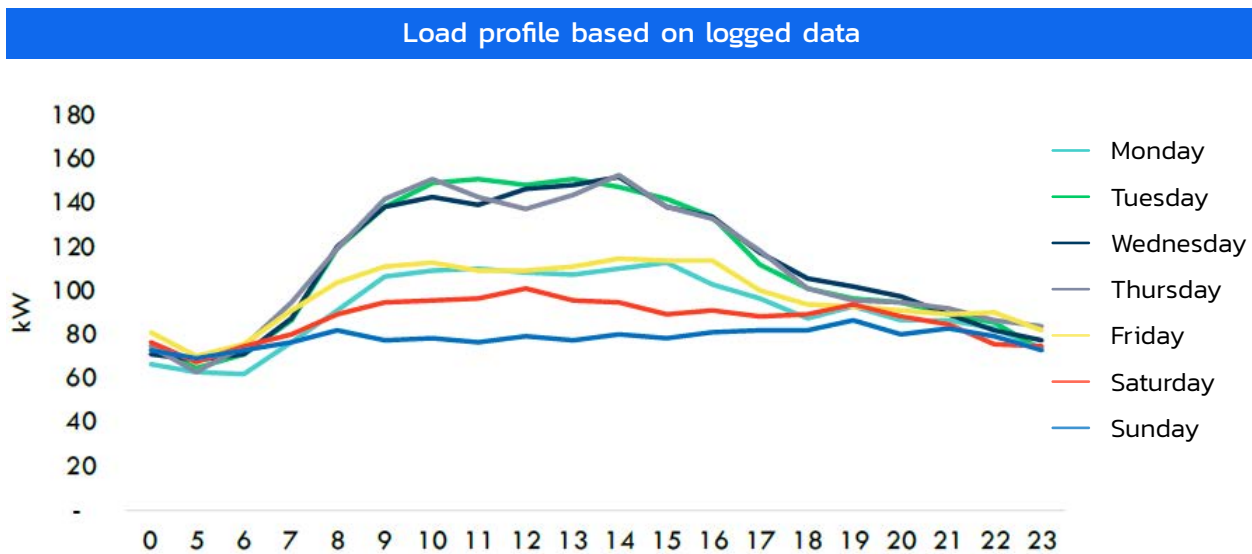
2.5.6 CUSTOMER 6

Customer 6 is a private hospital located in Utako district of Abuja. The hospital runs for 24 hours and 7 days a week providing full range of medical services. Our analysis of Customer 6 power consumption data suggests high daytime peak energy demand of 160 kW, and an average demand of 124 kW. Given the nature of the operation, reliability of power supply is crucial and Customer 6 uses both grid electricity and backup self-generation (we estimated the division to be

50/50 based on reported data). The facility has about 5,000 m² of rooftop and surrounding space available and can accommodate the optimal sizing of solar in our design. Deploying utility-enabled DER solution can help Customer 6 access reliable electricity and save on energy costs.

The average daily load profile and system design for Customer 6 are shown below.

Figure 11 Average daily load profile and system design for Customer 6



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 6 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 15 Grid upgrade recommendations for Customer 6

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of one damaged cross-arm along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

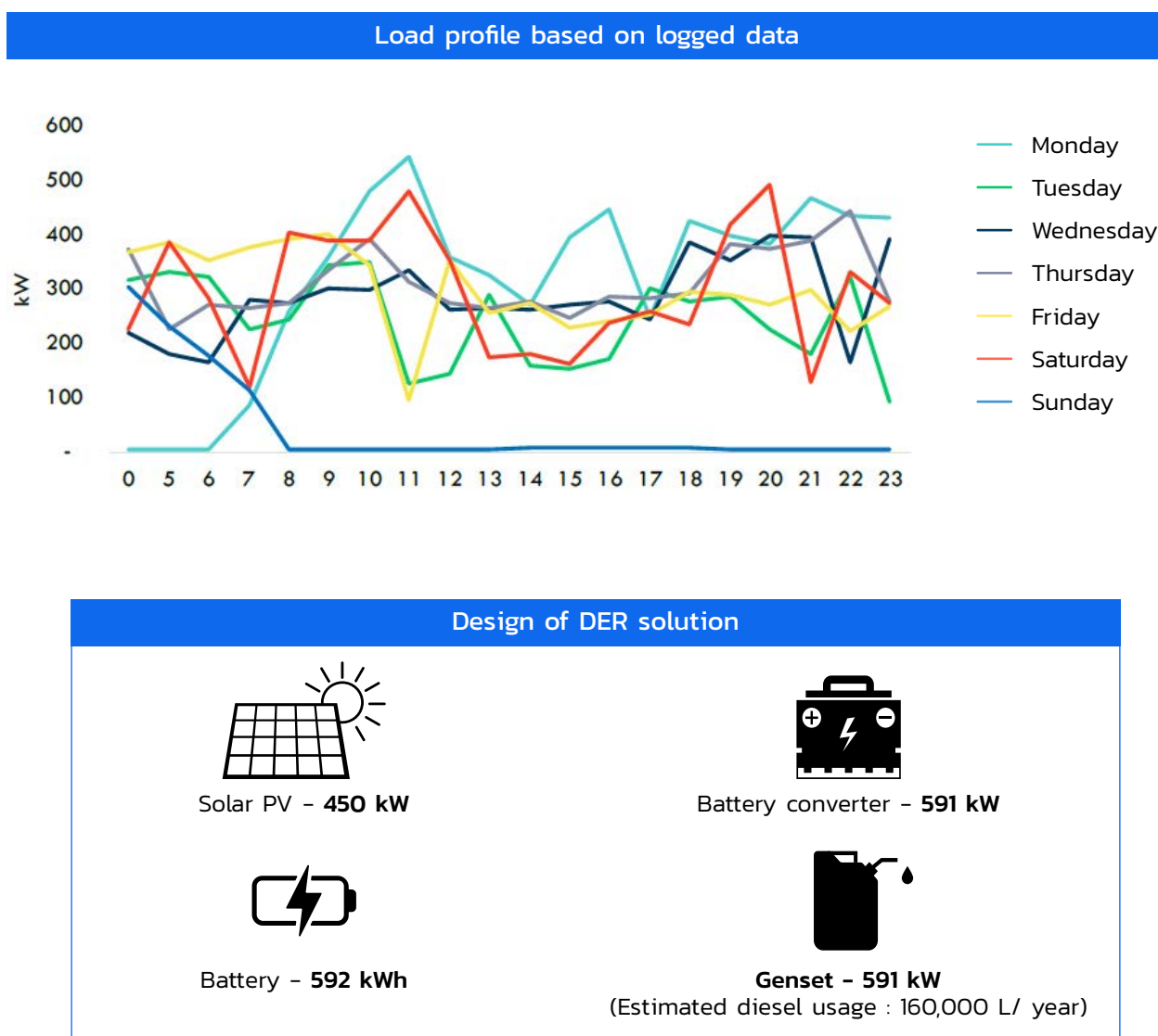
2.5.7 CUSTOMER 7

Customer 7 produces plastic blow-molded and injection molded packages, including household goods and cosmetics packages, food packages, chemical packages, buckets, plastic container caps, etc. Our analysis of Customer 7 power consumption data suggests high daytime peak energy demand of 590 kW, and an average demand of 295 kW. The feeder Customer 7 is connected to has low availability (same feeder as [REDACTED]) and to keep business operation, the site has to resort to diesel backup. We estimated a grid consumption

or self-generation division of 40/60, based on reported data. The facility has about 3,000 m² rooftop space available for solar installation, which is not enough for the optimal sizing. With the space constraint, we designed the solar PV to be 450 kW. Customer 7 makes a great candidate for the utility-enabled DER business model.

The average daily load profile and system design for Customer 7 are shown below.

Figure 12 Average daily load profile and system design for Customer 7



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 7 (and [REDACTED] as the two companies share location), accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 16 Grid upgrade recommendations for Customer 7

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of four damaged cross-arms along feeder	[REDACTED]
Replacement of one pair of tie straps along feeder	[REDACTED]
Replacement of two sets of stay wires along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]



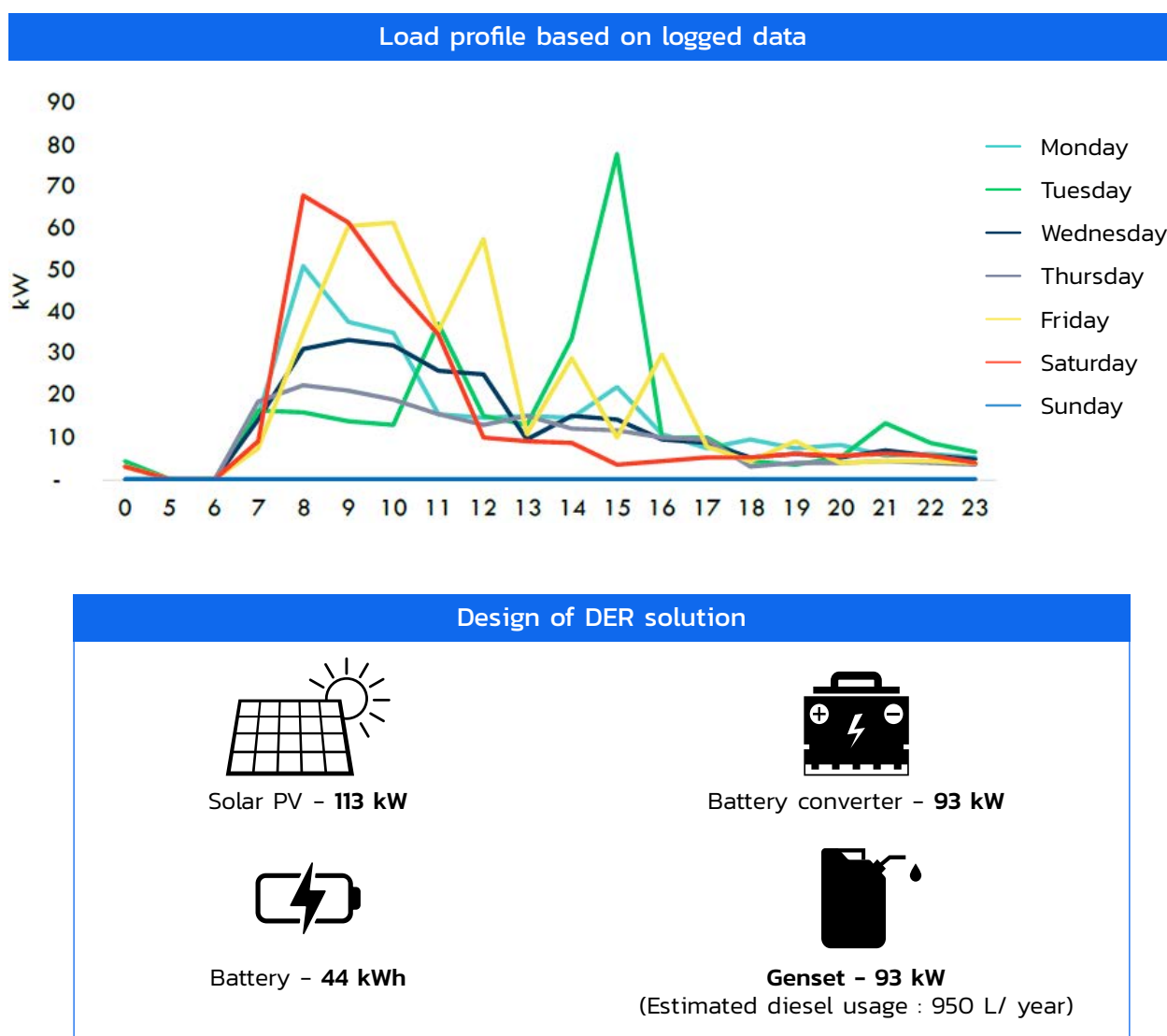
2.5.8 CUSTOMER 8

Customer 8 is the sister company of [REDACTED] and situated in the same vicinity. The company manufactures silk plaster, mineral plaster, construction paints, synthetic paints, varnishes, decorative exterior wall coatings, effect interior paints, etc. Our analysis of Customer 8 power consumption data suggests high daytime peak energy demand of 90 kW, and an average demand of 22 kW. Similar to its neighbor [REDACTED] we estimated that about 40–60% of load is met by

running backup diesel generators. The facility has about 1,500 m² rooftop space available for solar installation, which is sufficient for the optimal sizing of solar. Deploying utility-enabled DER solution has potentially to improve the reliability of electricity supply and save energy costs for the customer.

The average daily load profile and system design for Customer 8 are shown below.

Figure 13 Average daily load profile and system design for Customer 8



Customer 8 and [REDACTED] are sister companies situated in the same facility, recommendations for the critical grid upgrades are the same (see grid upgrade recommendations for Customer 8 above).

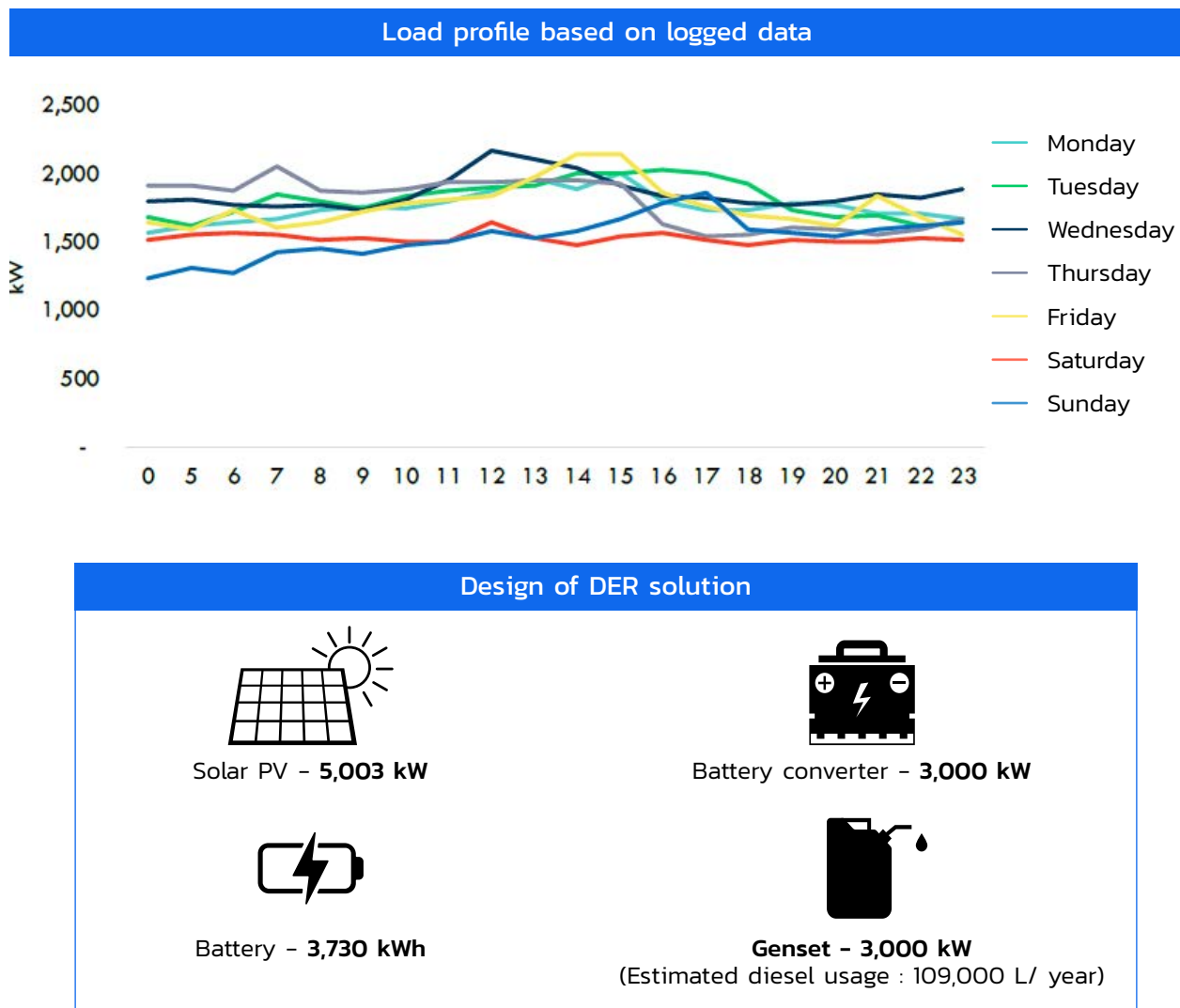
2.5.9 CUSTOMER 9

Customer 9 is a subsidiary of the [REDACTED] and one of the largest soft drink manufacturers in Nigeria. Customer 9 bottles and sell beverages, and has eight factories across Nigeria. The corporate has set emission reduction goals, and Daystar has partnered with since 2020 to provide renewable energy solutions. In the Abuja plant, Daystar has installed a 1.5-MW solar system. Our analysis of Customer 9 power consumption suggests the facility has high energy demand and operates seven days a week—the peak demand can reach 3MW, and the average demand is around 1.8MW.

There is opportunity to enhance the Daystar–Customer 9 collaboration by improving the power supply and partnering with AEDC. The proposed utility-enabled business model can help Customer 9 further save on diesel costs and contributing to the sustainability commitments.

The average daily load profile and system design for Customer 9 are shown below. Note that more detailed assessment of available physical space for DER installation is needed, especially with the existing solar panel.

Figure 14 Average daily load profile and system design for Customer 9





Customer 9 is connected to the [REDACTED] 33kV feeder, which is a dedicated line for Nigerian Railway Corporation, Economic and Financial Crimes Commission, Federal Medical Center Abuja and [REDACTED]. The line can already offer the customer with a minimum 18 hours of supply and a higher reliability to many other customers in Idu. After field assessment, the Afry team recommends that AEDC promptly control the vegetations along the distribution line, as part of its routine maintenance. The location of affected poles (GPS coordinates) is included in the Grid Upgrade Study Reports.

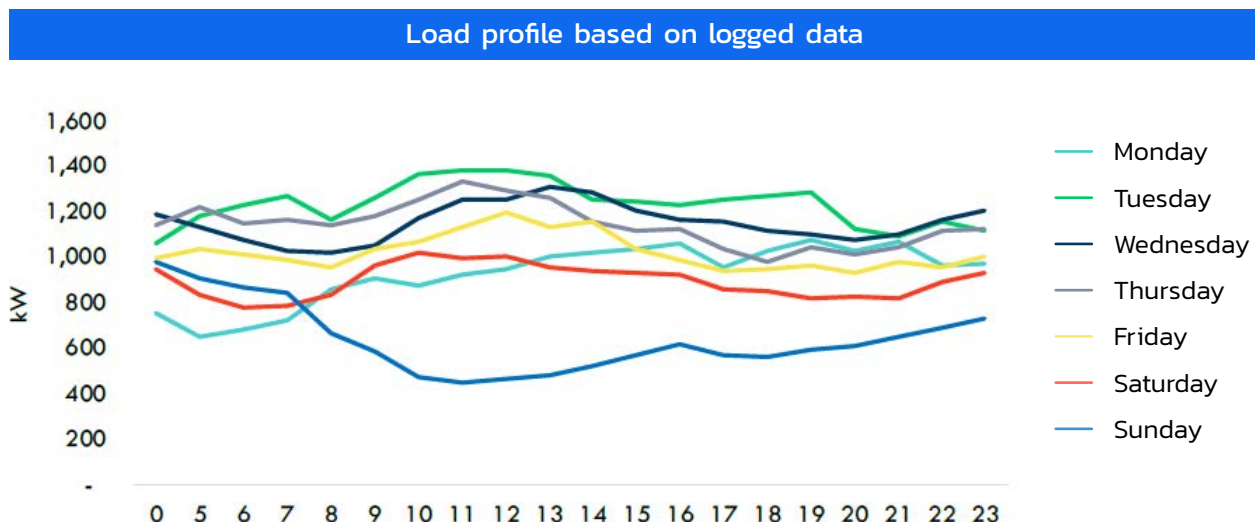
2.5.10 CUSTOMER 10

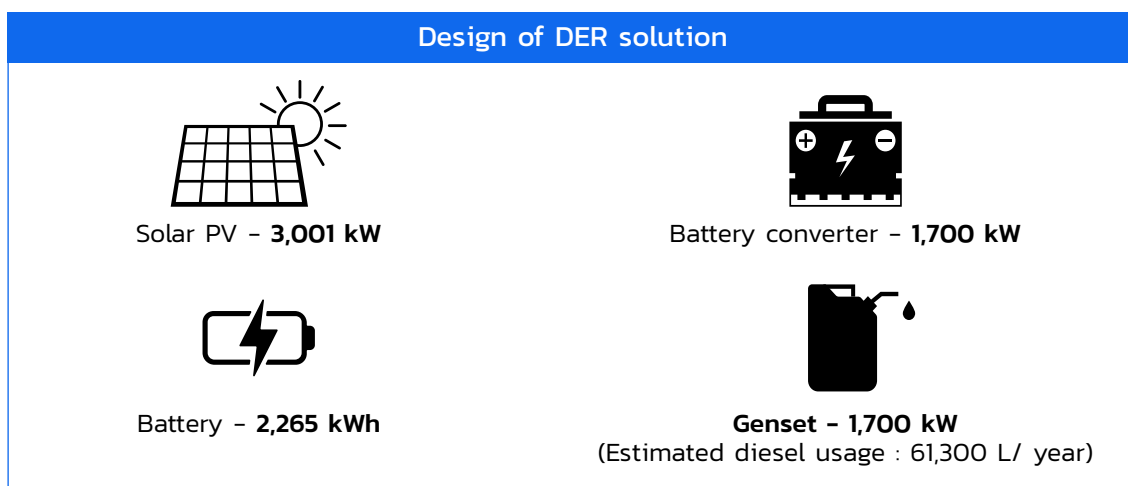
Customer 10 is one of the largest manufacturing companies in Nigeria, producing and distributing soft drinks including [REDACTED] etc. Customer 10 has nine plants across Nigeria, and we are assessing the facility in Idu Industrial District in Abuja. Our analysis of Customer 10 power consumption suggests the facility has high energy demand and operates seven days a week—the peak demand can reach 1.7MW and the average demand is above 1MW. The Abuja plant already has 950-kW solar installed onsite (without energy storage), a project developed by Daystar in 2022. There is

interest from both Daystar and the customer to enhance the onsite DER system and adapt to a utility-enabled business mode, to provide more reliable power supply to Customer 10 Abuja, while providing cost savings.

The average daily load profile and system design for Customer 10 are shown below. Note that more detailed assessment of available physical space for DER installation is needed, especially with the existing solar panel.

Figure 15 Average daily load profile and system design for Customer 10





The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 10, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 17 Grid upgrade recommendations for Customer 10

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of three damaged cross-arms along feeder	[REDACTED]
Replacement of three pairs of tie straps along feeder	[REDACTED]
Replacement of two sets of stay wires along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

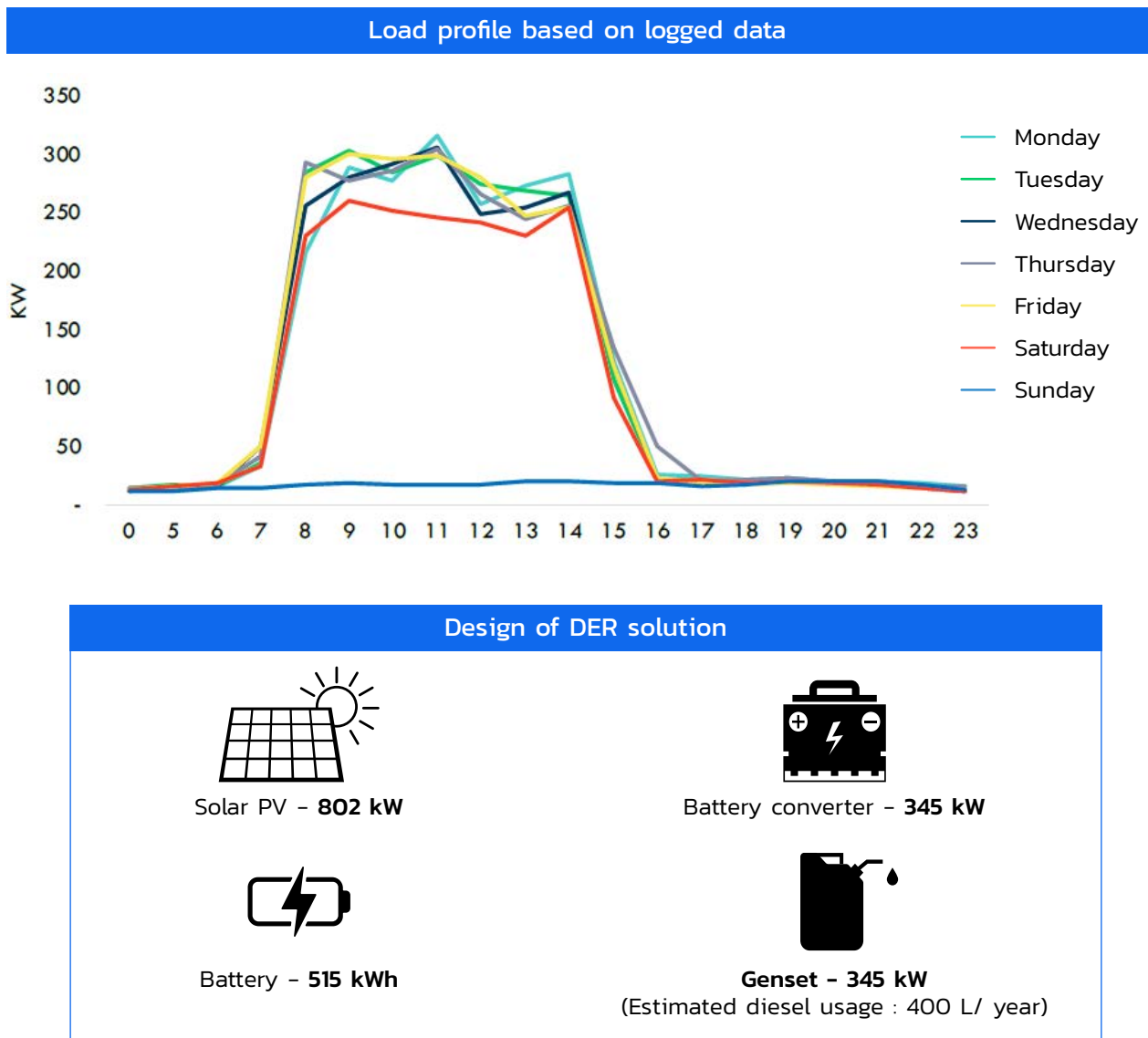
2.5.11 CUSTOMER 11

Customer 11 is a furniture manufacturer with a factory in Idu Industrial District in Abuja. It typically operates from 8am–5pm, Monday–Saturday. Our analysis of Customer 11 power consumption data suggests high daytime peak energy demand of 345 kW, and an average demand of 260 kW. The site currently only receives eight hours of supply from the grid and mostly consumes grid power for non-critical loads. The facility has about 15,000

m² of rooftop space available for optimal solar installation. Customer 11 scores highly against our site selection criteria and can benefit from implementing DER solutions to reduce diesel consumptions and energy costs, while ensuring high reliability.

The average daily load profile and system design for Customer 11 are shown below.

Figure 16 Average daily load profile and system design for Customer 11





The table below outlines the critical grid upgrades that the RMI, Daystar, and AEDC teams have jointly agreed upon as the top priorities for Customer 11, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 18 Grid upgrade recommendations for Customer 11

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of six damaged cross-arms along feeder	[REDACTED]
Replacement of six pairs of tie straps along feeder	[REDACTED]
Replacement of four sets of stay wires along feeder	[REDACTED]
Replacement of a pole along the feeder	[REDACTED]
Upgrade of customer's transformer from 500kVA to 750kVA transformer	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

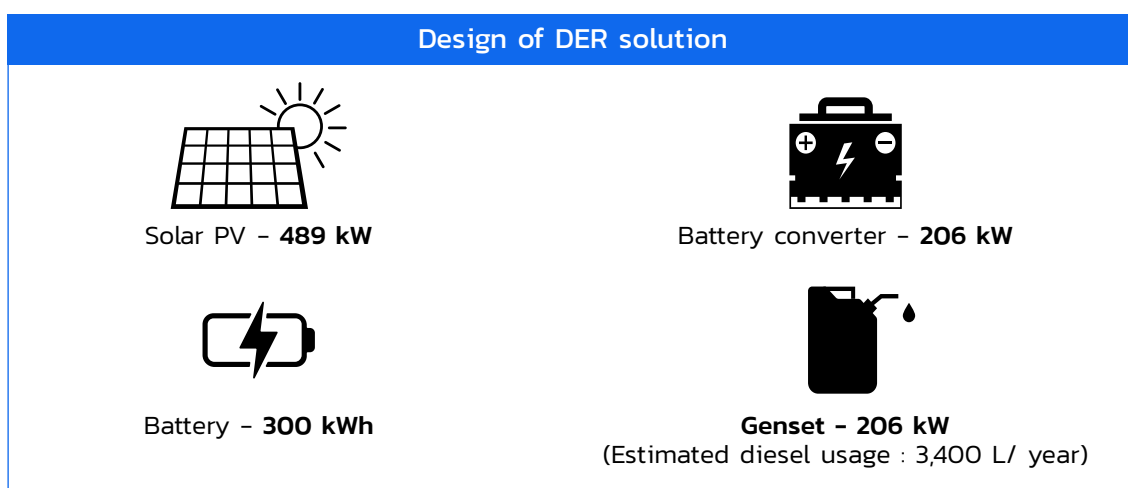
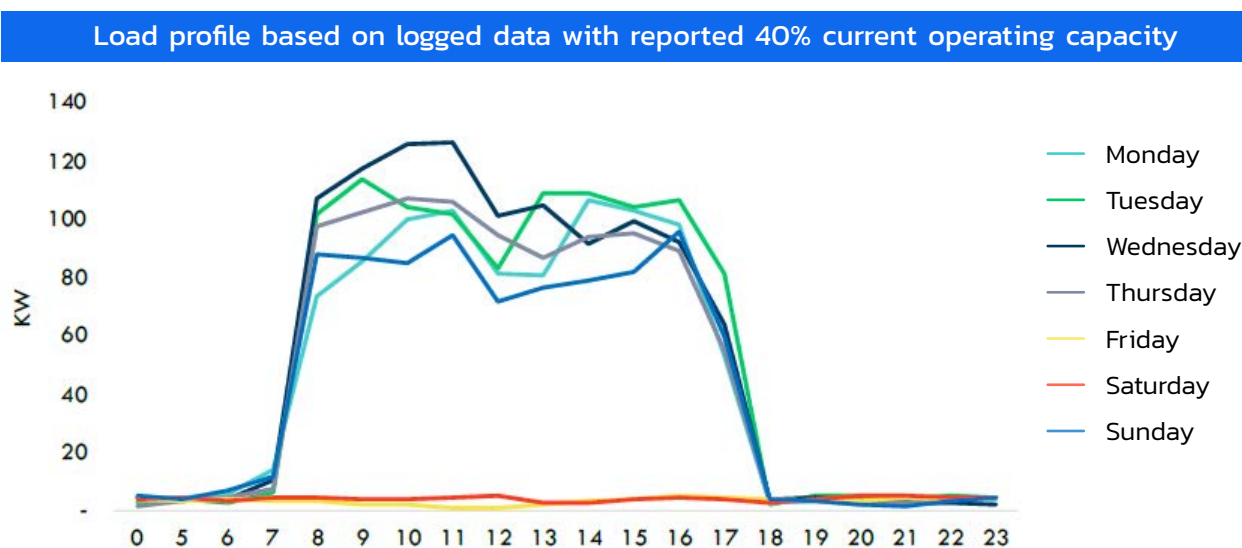
2.5.12 CUSTOMER 12

Customer 12 is a furniture manufacturer with a factory in Idu Industrial District in Abuja. Historically, the factory runs 24-hour shifts in high demand periods. Now the company is operating at reduced capacity due to high diesel price and poor macroeconomic conditions. Our analysis of Customer 12 power consumption data suggests high daytime peak energy demand of 130 kW, and an average demand of 100 kW. However, the utility manager reported it that the factory was running at about 40% capacity during the data logging period. With reliable and affordable electricity supply, Customer 12 intends to ramp

up operation again. To make sure we design the system capable of serving higher demand, we modeled with 1.5x of observed load (i.e., 200 kW peak and 150 kW average load). The factory is physically appropriate for solar PV installations with 10,000 m² of available rooftop space. The proposed utility-enabled business model can help Customer 12 resume normal business operations, access more reliable supply while reducing diesel consumption.

The average daily load profile and system design for Customer 12 are shown below.

Figure 17 Average daily load profile and system design for Customer 12



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 12, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.



Table 19 Grid upgrade recommendations for Customer 12

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of three damaged cross-arms along feeder	[REDACTED]
Replacement of five pairs of tie straps along feeder	[REDACTED]
Replacement of two sets of stay wires along feeder	[REDACTED]
Repair leaning poles and remove vegetation around poles	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

2.5.13 CUSTOMER 13

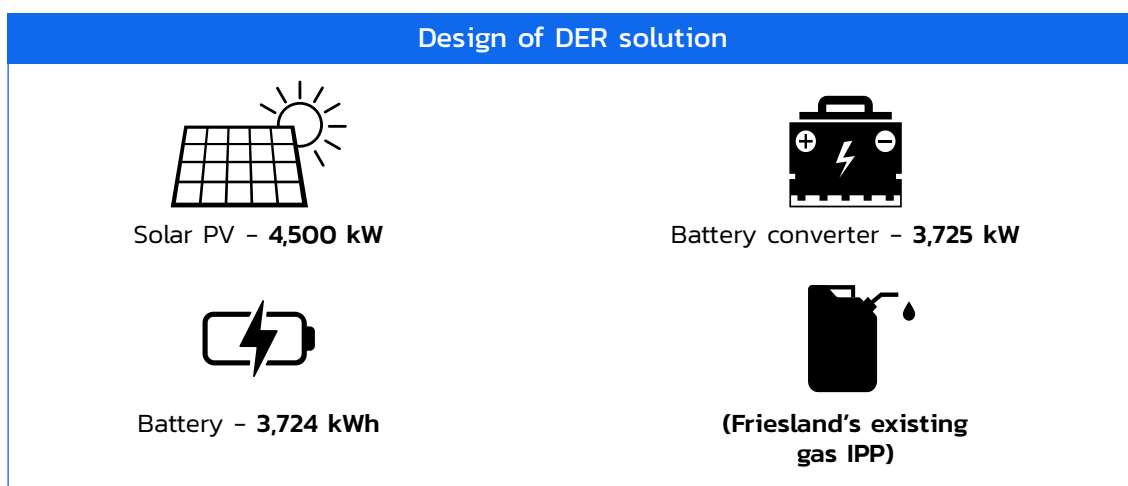
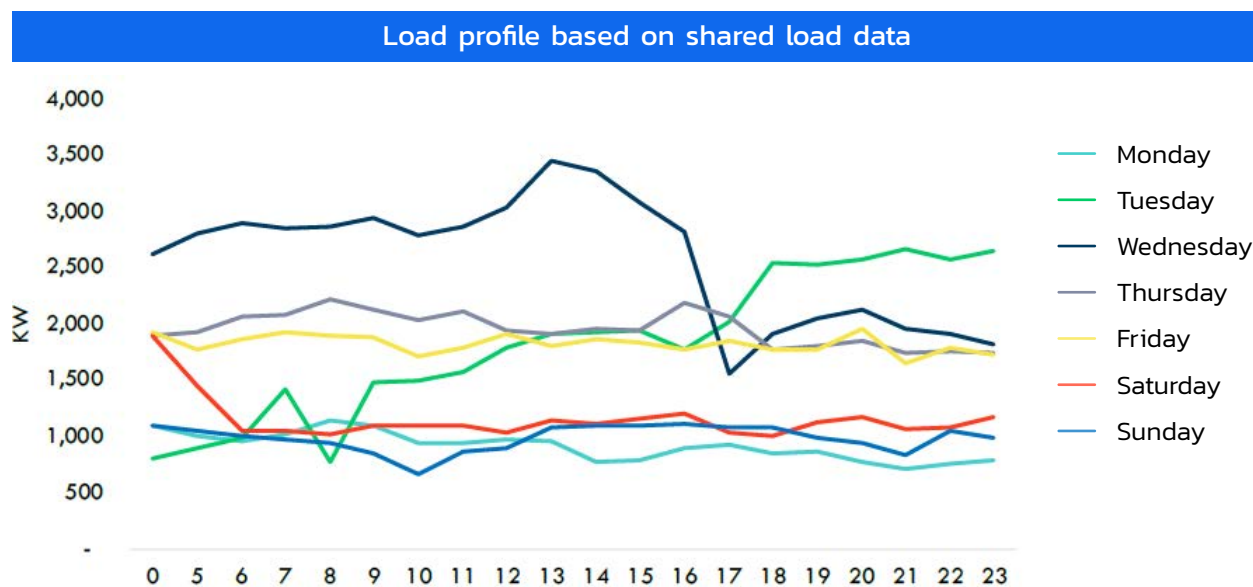
Customer 13 is one of Nigeria's foremost dairy manufacturers with strong family brands including [REDACTED]. We obtained one-week load data from the customer, which shows a peak energy demand of 3.5 MW, and an average demand of over 1.8 MW. Reliability is the top priority for Customer 13 even a few minutes' power outage can disrupt their production line significantly. In the absence of reliable grid supply, the company uses a 10MVA gas independent power producer (IPP) for power supply. Hence, we modeled gas as backup in the analysis (assuming that Customer 13 will integrate

the DER system with the existing gas IPP), as preferred by the customer. The facility is physically appropriate for solar DER installations with more than 30,000 m² of rooftop and ground space available, which we estimate can accommodate up to 4.5MW of panels. Deploying utility-enabled DER solution can help the company access reliable supply and save on energy costs, and support their corporate renewable energy goals.

The average daily load profile and system design for Customer 13 are shown below.



Figure 18 Average daily load profile and system design for Customer 13



In December 2022, Ikeja Electric reconnected Customer 13 into the grid and has implemented necessary distribution network upgrades to supply a minimum of 18 hours to the site. No additional grid upgrade is needed at this point.



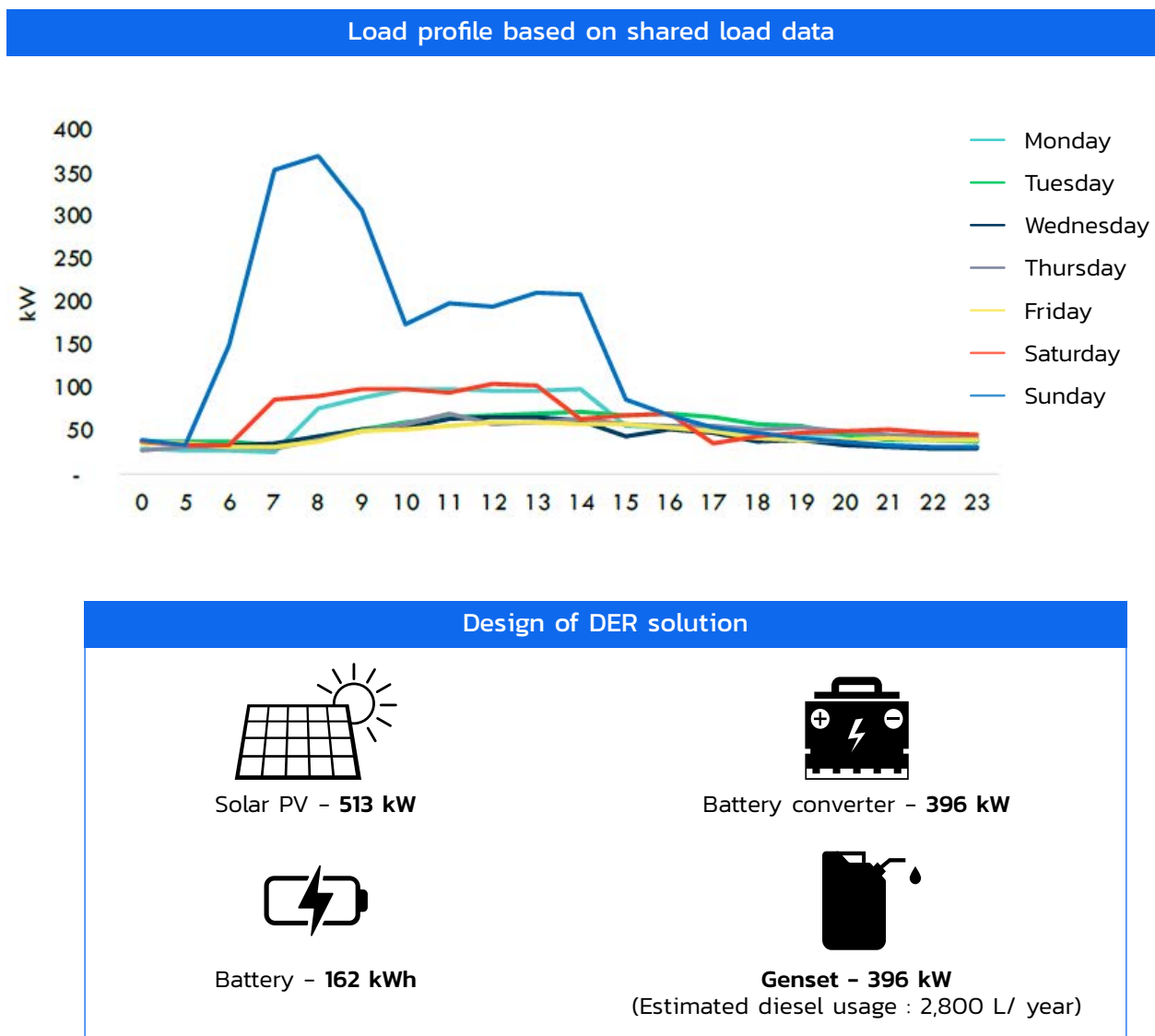
2.5.14 CUSTOMER 14

Customer 14 is a prominent megachurch and Christian denomination with a long history in Nigeria. [REDACTED] is one of its campuses in Lagos and can host a maximum of 15,000 worshipers. Customer 14 is open 24/7 with most activities and programs happening on Sundays. Our analysis of Customer 14 power consumption data suggests high Sunday peak energy demand of 380 kW, and an average demand of 80 kW overall. The site utility manager reported that they currently use 50% of diesel generator (sometimes compressed natural gas) and 50% of grid for power supply.

The facility is physically appropriate for DER installation with about 12,000 m² space available for solar. And by deploying DER, Customer 14 is hoping to reduce energy costs and improve power reliability.

The average daily load profile and system design for Customer 14 are shown below. We designed the DER system to be able to meet the significant higher Sunday loads, but can refine further based on customer's priorities.

Figure 19 Average daily load profile and system design for Customer 14



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 14 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 20 Grid upgrade recommendations for Customer 14

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of one damaged pole along the feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

2.5.15 CUSTOMER 15

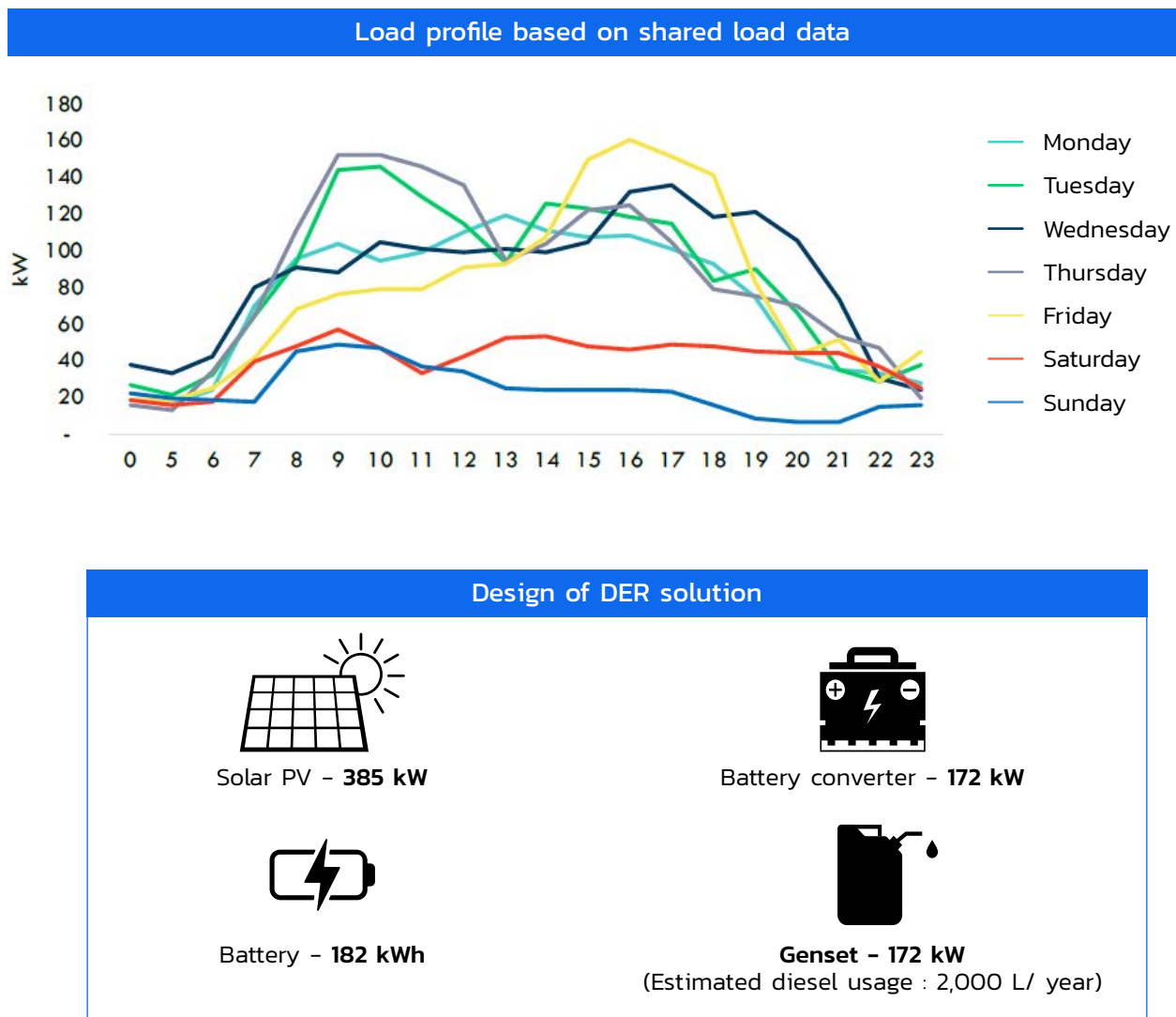
Customer 15 operates as a limited liability company serving the megachurch. The entity is responsible for producing [REDACTED] copies catering to children, teenagers and adults. Books authored by the Church's General Overseer, Pastor [REDACTED], are also assembled and distributed through this company. The company also houses a recording studio and operates a TV channel titled [REDACTED]. The company runs 24/7, although the majority of the staff follows a daily routine from 8am–5pm. Our analysis of Customer 15 power consumption data suggests high daytime peak energy demand of

170 kW, and an average demand of 90 kW. The company relies on both grid and diesel self-generation for power supply and we estimate the division to be 60/40. The facility has about 7,000 m² of space available for solar installations, sufficient for optimal sizing. DER solutions can help Customer 15 access more reliable and cheaper energy supply.

The average daily load profile and system design for Customer 15 are shown below.



Figure 20 Average daily load profile and system design for Customer 15



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 15 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 11kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 21 Grid upgrade recommendations for Customer 15

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of one damaged crossarm along the feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes inequipment cost, etc.)	[REDACTED]
Total	[REDACTED]

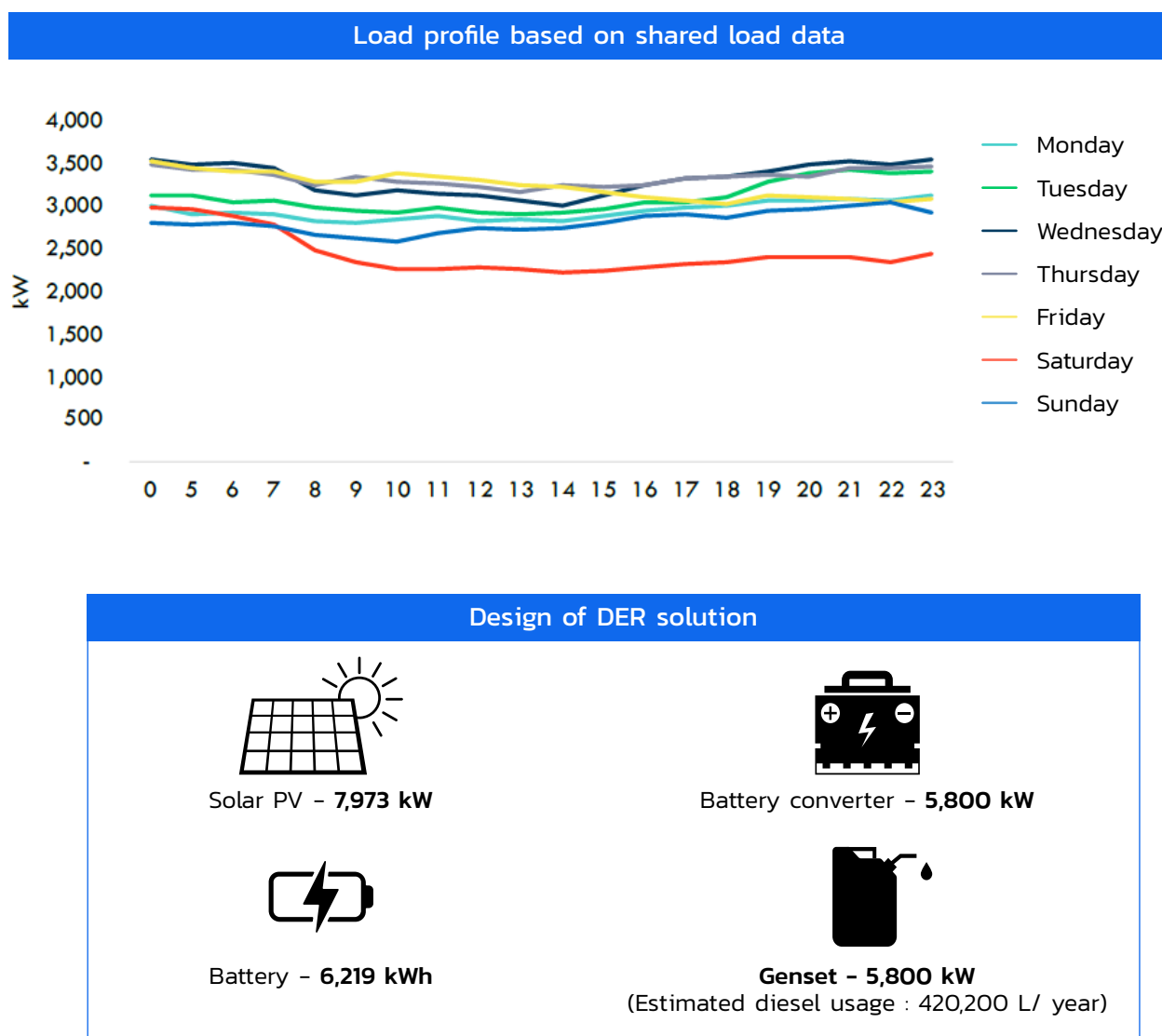
2.5.16 CUSTOMER 16

Customer 16 plant is the largest bottling plant in Africa that manages the production of [REDACTED] etc. and the distribution of all products. Daystar has developed a 627-kW solar system. Our analysis of Customer 16 power consumption suggests the facility has high energy demand and operates seven days a week—the peak demand can reach nearly 6MW, and the average demand is over 3MW. The plant is currently not connected to the distribution network, and there is opportunity to enhance the Daystar–Customer 16 collaboration by

improving the power supply and partnering with IE. The proposed utility-enabled business model can help Customer 16 further save on diesel costs and contributing to the sustainability commitments.

The average daily load profile and system design for Customer 16 are shown below. Note that more detailed assessment of available physical space for DER installation is needed, especially with the existing solar panels.

Figure 21 Average daily load profile and system design for Customer 16





Customer 16 is currently not connected to the grid and there is strong interest from IE to extend the nearest feeder line [REDACTED] 33 kV feeder, about 750 meter from the closest pole) and connect Customer 16 to its distribution network. IE confirmed that the Customer 16 feeder currently can offer a minimum 18 hours of supply and expected so for [REDACTED] once connected. After field assessment, the Afry team recommends prompt and regular vegetation control along the distribution line, and provides a high-level cost estimates for extending the distribution network to connect Customer 16. Additional details are included in the Grid Upgrade Study Reports.

Table 22 Estimated cost for extending 33kV grid supply to Customer 16

[REDACTED]

Although the network extension cost is significant and much higher than estimated grid upgrade costs at other sites, connecting Customer 16 to the grid will bring IE sizable new revenue that IE can easily recoup the infrastructure investment from. Recognizing this might be beyond what Daystar would help finance, Daystar and IE teams would have to align further on the network extension financing and implementation plans.

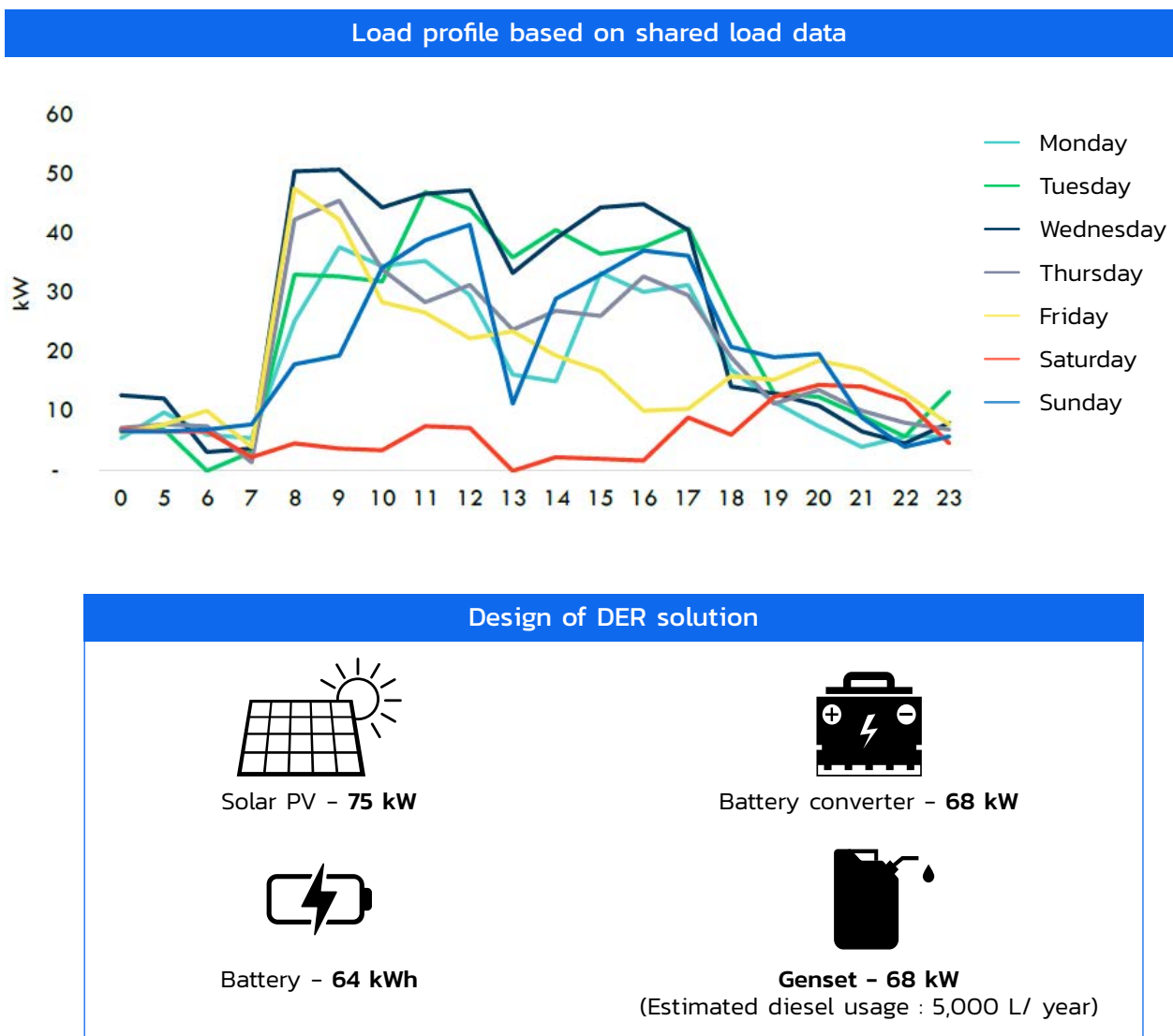
2.5.17 CUSTOMER 17

Customer 17 is a highly diversified business group dealing with steel stockist, haulage services, real estate, oil and gas. The company supplies and sells iron pod, pipes, purlins, etc. Our analysis of Customer 17 power consumption data suggests high daytime peak energy demand of about 50 kW, and an average demand of 32 kW. The facility's sources of power are grid and diesel generator, and with high diesel costs, operations are sometimes

affected. There is only about 500 m² of space available at the site, which is a limitation for solar sizing. Still, deploying utility-enabled DER is promising to help Customer 17 access more reliable power supply and reduce diesel costs.

The average daily load profile and system design for Customer 17 are shown below.

Figure 22 Average daily load profile and system design for Customer 17



The table below outlines the critical grid upgrades that the Afry team identified as the top priorities for Customer 17, accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 11kV feeder. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 23 Grid upgrade recommendations for Customer 17

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of two damaged crossarms along the feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes inequipment cost, etc.)	[REDACTED]
Total	[REDACTED]

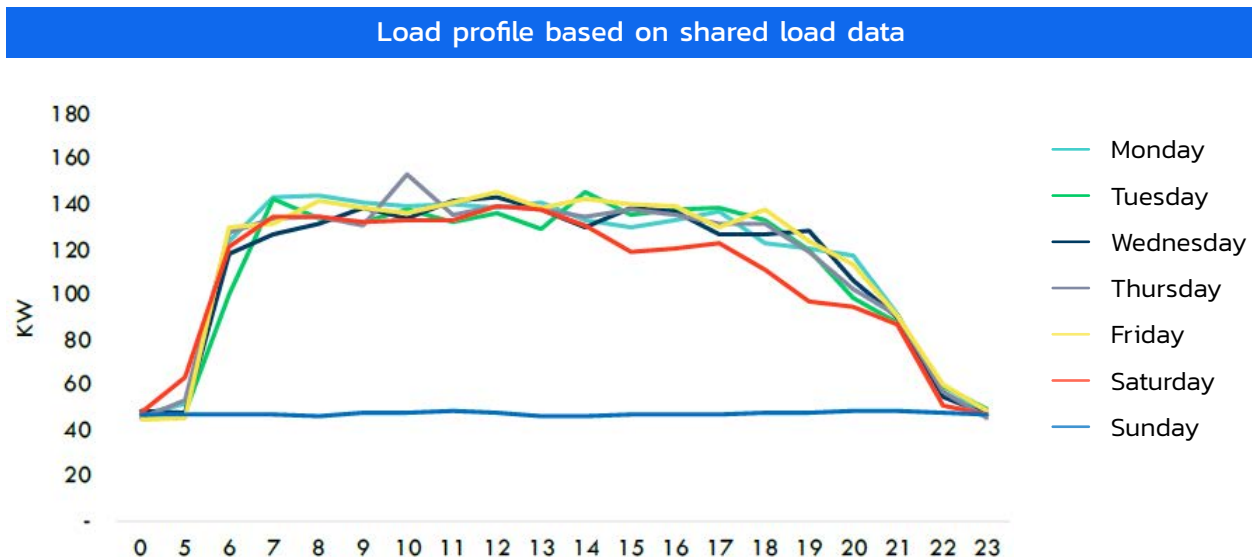
2.5.18 CUSTOMER 18

Customer 18 is a supermarket located in Victoria Island, Lagos, and has fairly consistent electricity demand from air-conditioning, refrigerators and freezers, cooking and lighting. Our analysis of Customer 18 power consumption data suggests high daytime peak energy demand of 160 kW, and an average demand of 135 kW. To complement grid supply, the customer has to run diesel backup generator for long hours, and the utility-enabled

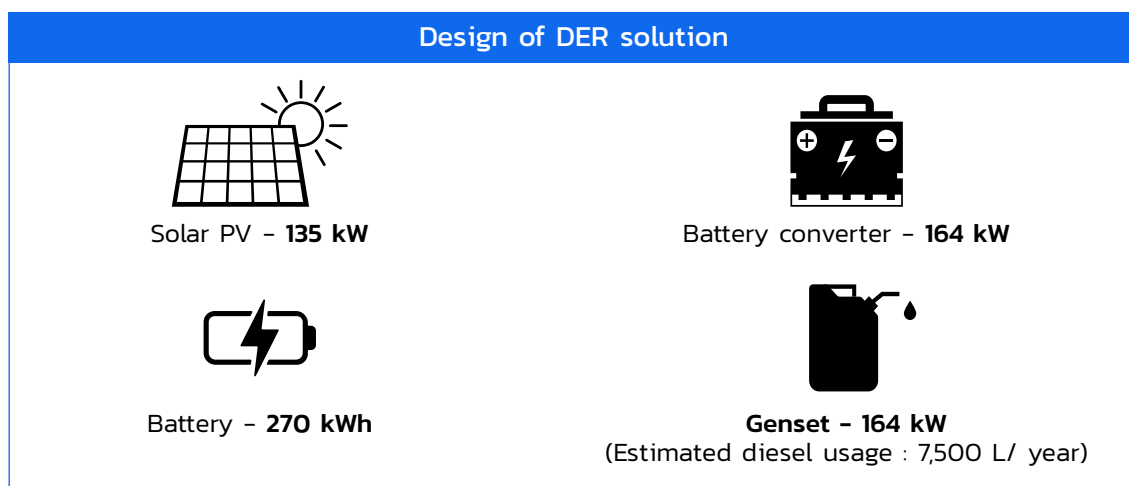
DER solution has potential to help customer achieve higher reliability, reduce diesel consumption and costs. The facility has about 900 m2 of rooftop space and 300 m2 of carport space available for optimal solar sizing.

The average daily load profile and system design for Customer 18 are shown below.

Figure 23 Average daily load profile and system design for Customer 18



With engagement challenges and slow response from EKEDC since their leadership change in early 2023, we were unable to confirm the field study plan with EKEDC to assess the distribution network for Customer 18 within reasonable timeline of the feasibility study. Daystar and RMI will continue to engage EKEDC to advance utility-enabled DER implementation and manage the relationship.



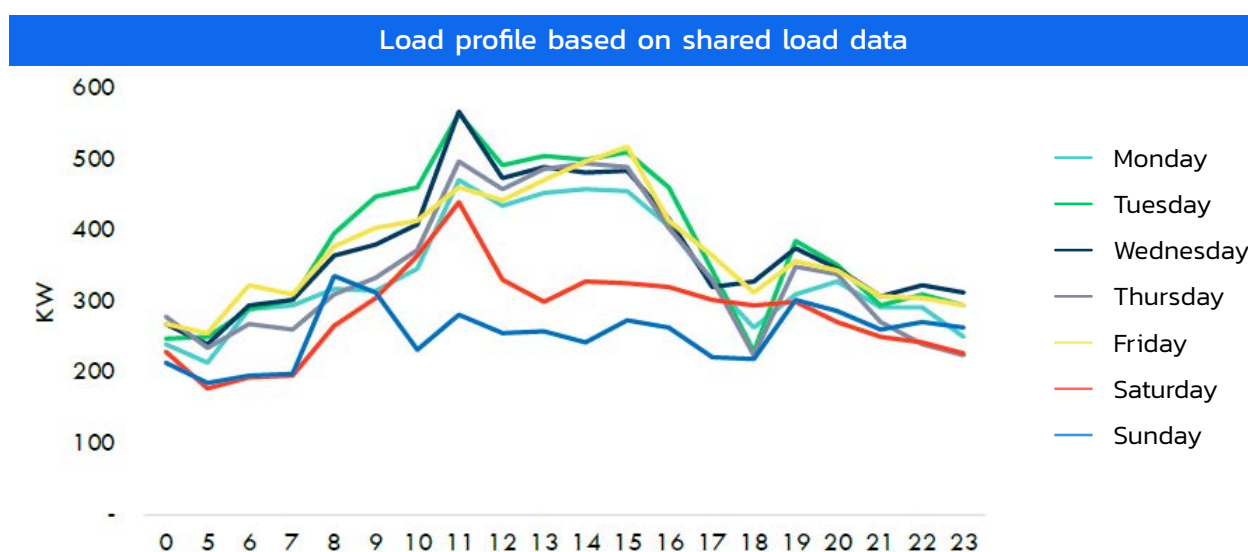
2.5.19 CUSTOMER 19

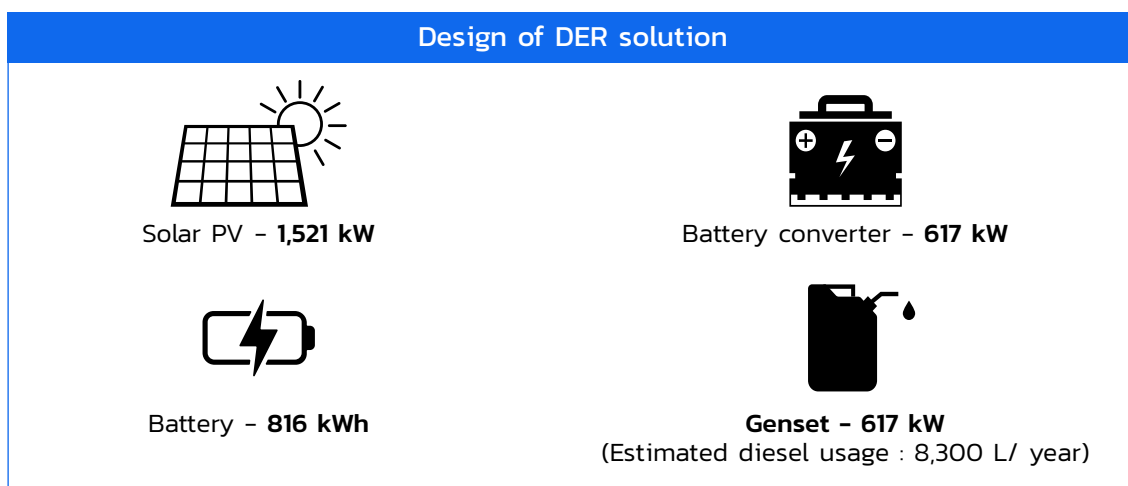
Customer 19 is a day and boarding school located in Lagos with high energy demand, primarily from air-conditioners and water heaters. The school only gets about two hours of grid supply per day and owns multiple diesel gensets to meet various energy needs. The school also already has 700 kW PV onsite developed by Daystar, and is interested in expanding DER solutions. Our analysis of Customer 19 power consumption data

suggests a peak energy demand of 600 kW, and an average demand of 410 kW. The school campus is physically appropriate for solar PV installations with 10,000 m² of available rooftop and ground spaces.

The average daily load profile and system design for Customer 19 are shown below.

Figure 24 Average daily load profile and system design for Customer 19





With engagement challenges and slow response from EKEDC since their leadership change in early 2023, we were unable to confirm the field study plan with EKEDC to assess the distribution network for Customer 19 within reasonable timeline of the feasibility study. Daystar and RMI will continue to engage EKEDC to advance utility-enabled DER implementation and manage the relationship.

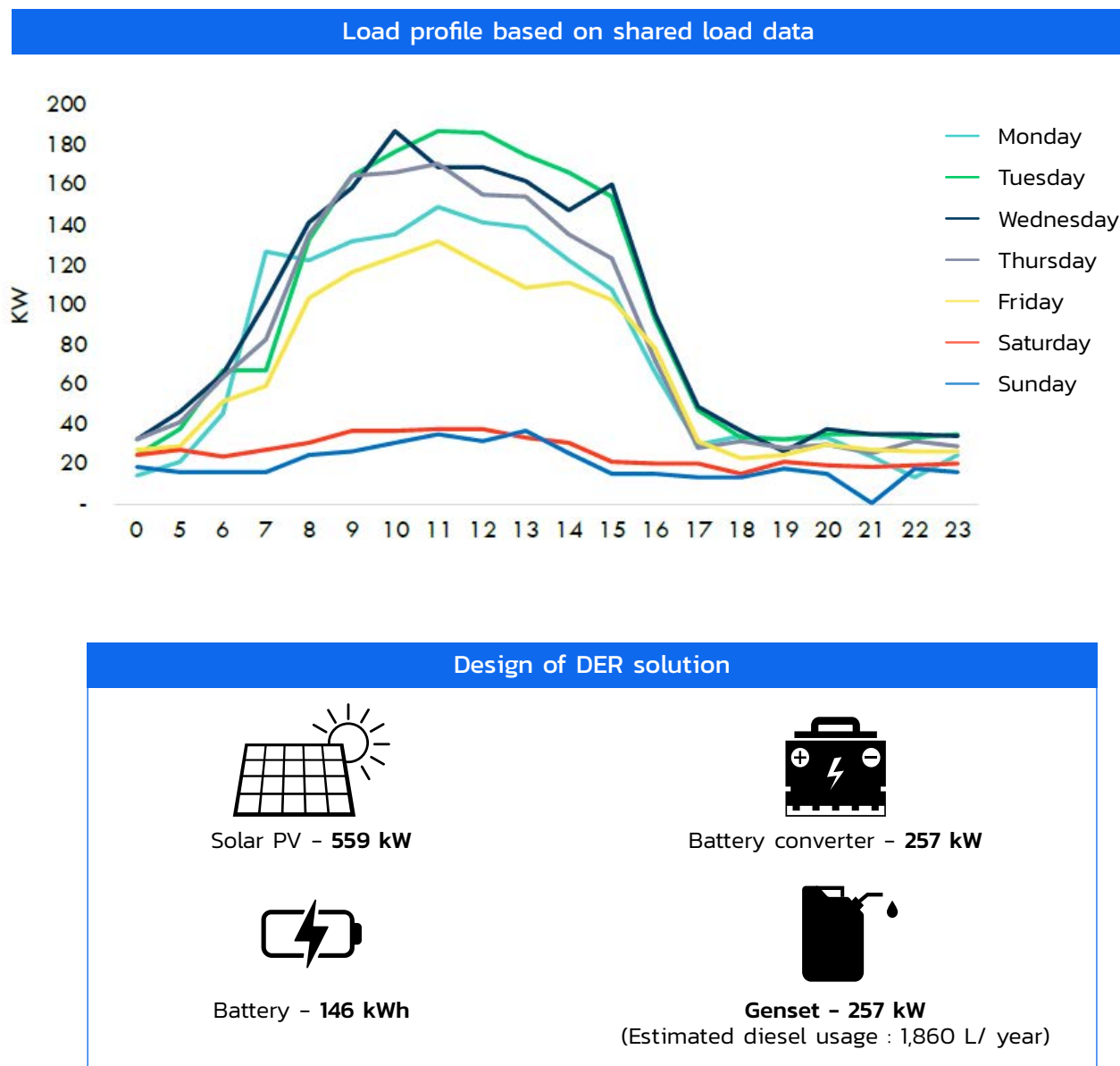
2.5.20 CUSTOMER 20

Customer 20 is a day school located in Lagos with high energy demand, primarily from air-conditioners and school appliances (computers, projectors, etc.). The school owns multiple diesel gensets and the utility manager reported an average consumption of 1,300 L per month. Our analysis of Customer 20 power consumption data suggests a peak energy demand of 250 kW, and an average demand of 145 kW. The campus has 4,000 m² of available rooftop space, sufficient for

optimal sizing of solar. Deploying utility-enabled DER solution has the potential for the school access reliable supply and reduce diesel cost.

The average daily load profile and system design for Customer 20 are shown below. Note that the battery is sized to supply one hour of average load (instead of two hours), considering the reported grid availability and the school's operation shouldn't be severely impacted.

Figure 25 Average daily load profile and system design for Customer 20



The Afry team recommends feeder maintenance to improve grid supply, including repositioning of leaning poles, tightening of guy wires and reinforcement of cracked concrete poles. The costs may vary depending on if DisCo staff can perform these as part of the regular feeder maintenance. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder from Lekki Transmission Substation in EKEDC. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

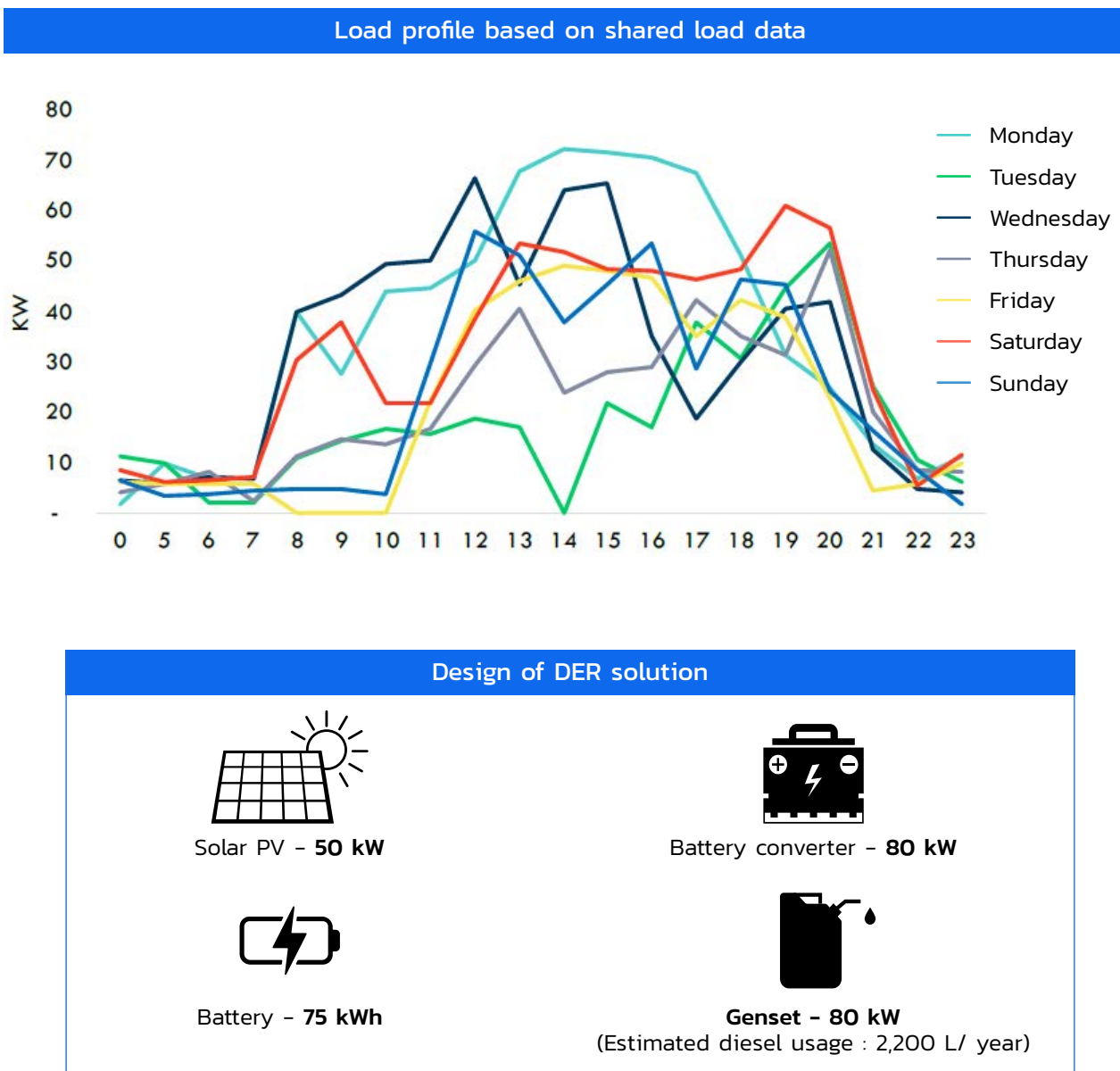
2.5.21 CUSTOMER 21

Customer 21 is a shopping complex, located in Lekki area of Lagos. The mall operates around the year, with typical operating hours from 8am–10:30pm. The complex houses a supermarket, a pastry shop/restaurant, a laundromat, a rooftop restaurant and other retail businesses. The shopping complex gets 50% power from the grid and the other 50% from diesel generators. The diesel generating hours have been throttled due to the high cost of diesel, and some of the tenants now resort to using their own backup generators. Our analysis of the mall's

power consumption data suggests a peak energy demand of 80 kW, and an average demand of 37 kW. Solar sizing is constrained by space, as the complex only has 330 m² of available rooftop space (enough for installing 50 kW solar). Still, the customer can benefit from onsite DER to reduce energy costs.

The average daily load profile and system design for Customer 21 are shown below.

Figure 26 Average daily load profile and system design for Customer 21



The table below outlines the critical grid upgrades that the Afry team have identified as the top priorities for Customer 21 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder from Lekki Transmission Substation in EKEDC. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Figure 27 Average daily load profile and system design for Customer 21

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Replacement of two sets of stay wires along feeder	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

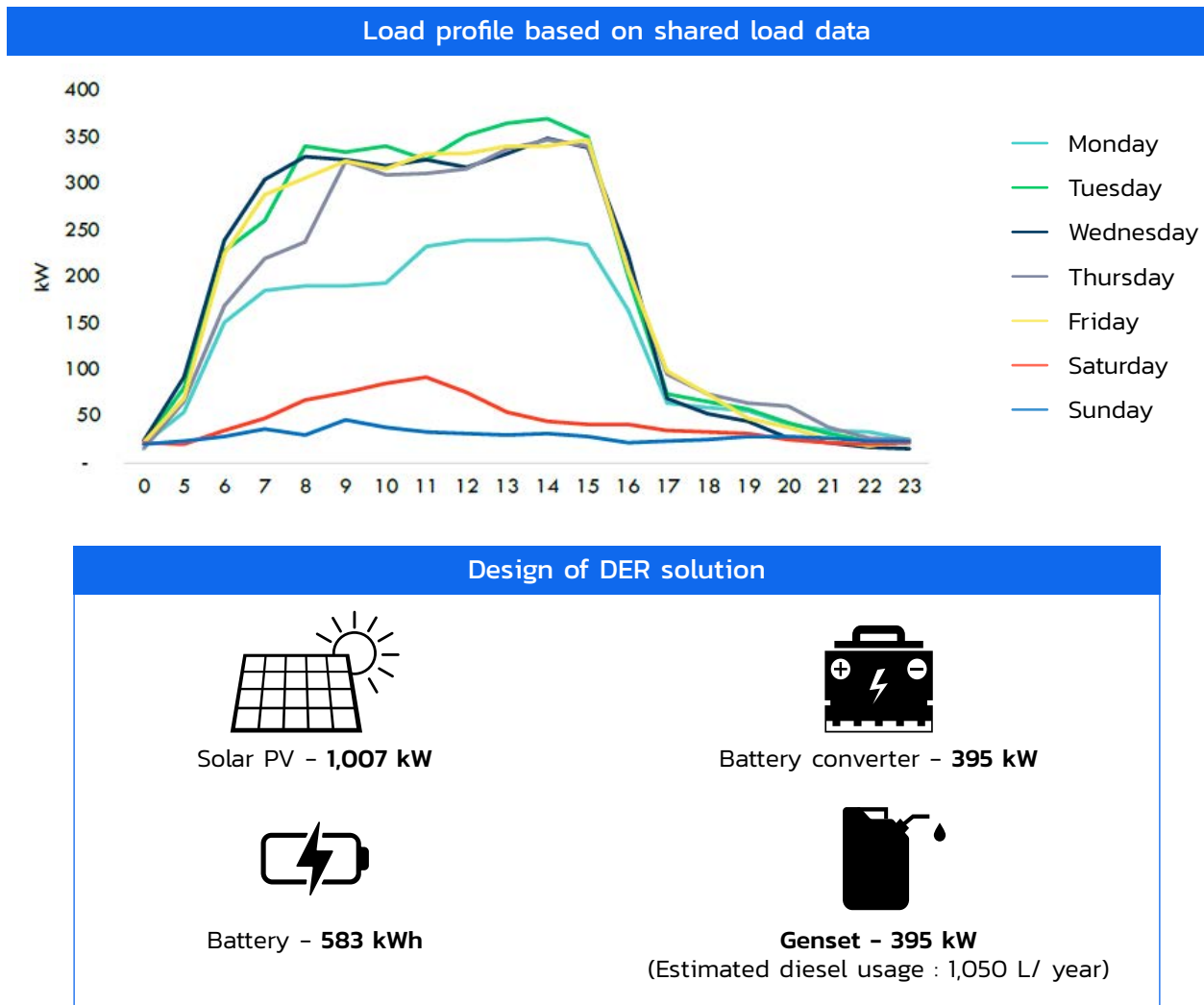
2.5.22 CUSTOMER 22

Customer 22 is a secondary school, located in Lekki area of Lagos. It operates on a typical school calendar cycle–September to December (1st school term), January to March (2nd school term) and May to July (3rd term) and has high day-time energy demand, primarily from air-conditioning, fans, computers, lighting, and water pumps. Our analysis of Customer 22 power consumption data suggests a peak energy demand of 390 kW, and an average demand of 290 kW. Due to unpredictable grid supply, the school is currently completely defected from the grid and buys power through a power purchase agreement (at ₦74/kWh), while also running a backup diesel generator. The school campus has about 3,000 m2 rooftop space and 5,000 m2 carport space available, which would allow optimal solar sizing. Deploying onsite DER has potential to help the school improve power reliability and reduce diesel consumption.

The average daily load profile and system design for Customer 22 are shown below.



Figure 27 Average daily load profile and system design for Customer 22



The table below outlines the critical grid upgrades that the Afry team have identified as the top priorities for Customer 22 accompanied by cost estimates. The recommendations were formulated after conducting a thorough assessment of the customer feeder, the [REDACTED] 33kV feeder from Lekki Transmission Substation in EKEDC. Additional details on each item, including the location of affected poles (GPS coordinates), pictures and quotes, are included in the Grid Upgrade Study Reports.

Table 25 Grid upgrade recommendations for Customer 22

RECOMMENDATIONS	COSTS ESTIMATES (NGN)
Repair of three leaning poles	[REDACTED]
Replacement of three sets of tie straps	[REDACTED]
Miscellaneous (20% of cost to cover labour, changes in equipment cost, etc.)	[REDACTED]
Total	[REDACTED]

03

**ECONOMIC AND
FINANCIAL
ANALYSIS**

This section includes a summary of the economic and financial modelling approach, assumptions, data inputs and results for the sites RMI evaluated. It also highlights scaling assumptions and their financial and operational impact on Daystar's business. Daystar can use this information for prioritizing sites for implementation based on capital requirements, return on investment, customer and DisCo's potential interest based on their economic benefits of participating in the tripartite agreement. USTDA can refer to this section to identify opportunities for supporting scaled deployment of the C&I DER business model based on the sensitivity impacts of key factors such as equipment costs and foreign exchange rates on the economic outcomes of implementing DERs at C&I sites.



3.1 APPROACH FOR ECONOMIC AND FINANCIAL MODELLING

KEY TAKEAWAYS

- The economic model is an Excel-based cashflow model that evaluates the net present value for Daystar and the DisCo, and estimates the customer's energy cost savings for each site.
- The financial model bundled project revenues, capital requirements, operational costs along with other financial assumptions to test Daystar's capacity to service debt in developing DER projects.
- For both models, RMI aligned key assumptions with Daystar and incorporated inputs from DisCos and desk research. Some of the modeling inputs are prone to change (such as DisCo tariffs, fuel price, foreign exchange rate), and it's important to revisit and re-calibrate the analysis when presenting the final project proposals to customers and DisCos.

3.1.1 ECONOMIC MODELLING APPROACH

RMI developed an economic model (individual customer models are included in the Task 3 close-out package) along with key assumptions and modelling inputs preapproved by the Daystar team prior to inclusion in the model. The economic model is an Excel-based cashflow model that incorporates DER capital and operation costs, grid upgrade costs, customer energy consumption, grid tariffs, among other inputs. The model calculates

Daystar and the DisCo's revenue, compare Business-as-Usual (BAU) and DER scenario net present values, estimate the blended tariff the customer will pay and the customer's energy cost savings. We used the model to complete economic viability assessments of the proposed utility-enabled DER business model, for the 22 selected C&I customers in Abuja and Lagos, Daystar as the developer, and DisCos.

The key assumptions that we used to shape the economic model are:

1

The customer's BAU energy costs are comprising a combination of grid and self-generation using diesel or gas generators. The division of grid consumption and self-generation are based on customer interviews supported by logged load data and/or utility bills (some customers fully rely on self-generation).

2

The DER scenario includes grid prioritized for early morning, evening and nighttime supply and a DER system prioritized for daytime supply and back-up for randomized grid outages generated in the HOMER model that are designed based on the agreed reliability that the DisCo can guarantee.

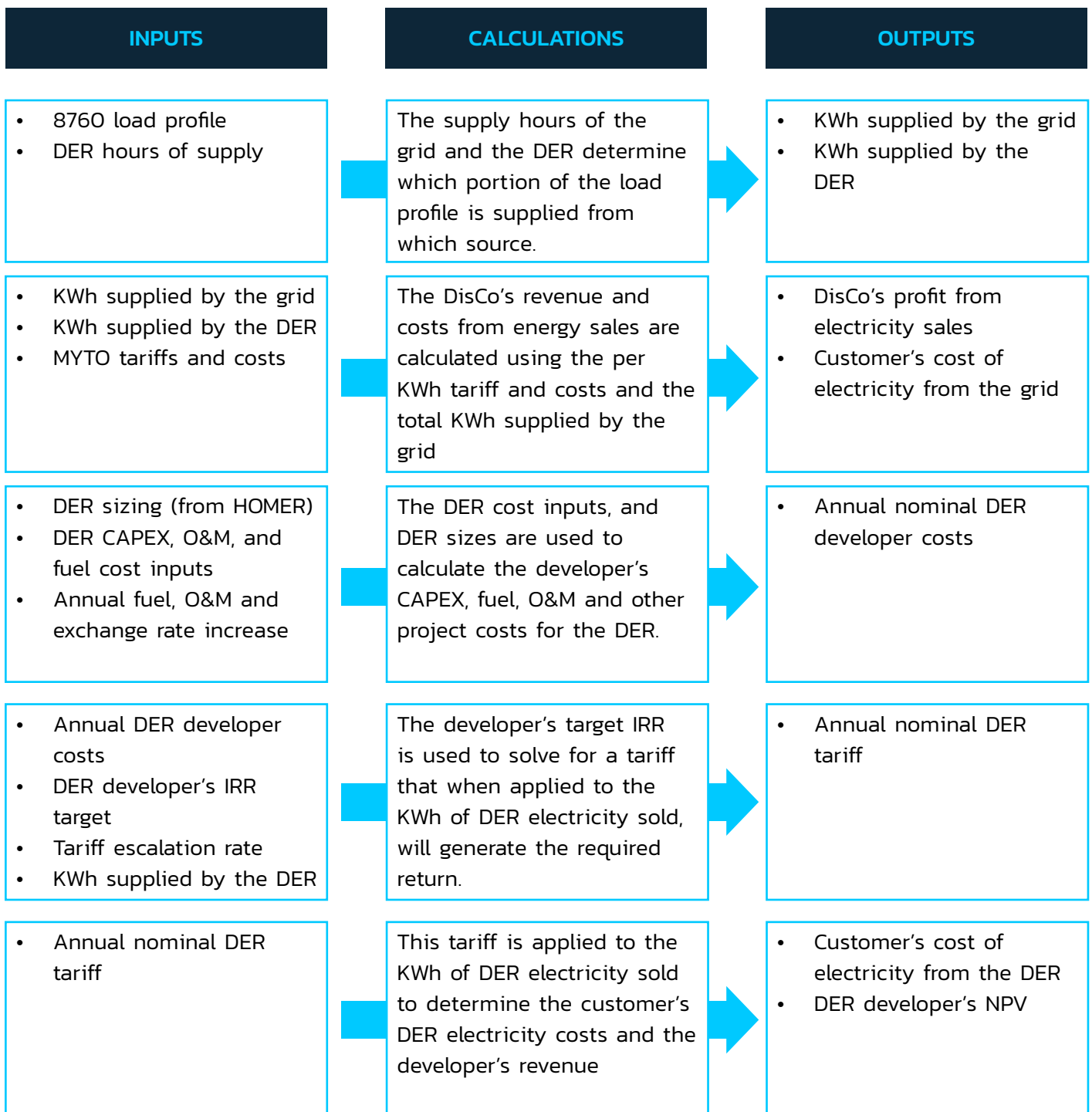
3

The customer pays a blended tariff to Daystar that combines DER costs and grid tariffs, calculated based on the power consumed from either source.



The economic modelling process involved multiple steps highlighted in the below and summarized in Figure 28 below.

Figure 28 : Summary of how the excel economic model computes economic outcomes for the customer, DisCo, and developer.



STEP

1

RMI developed a long list of inputs required by the model to complete computations of the economic outcomes for each party. These include costs for the DER components, capital costs for all the parties, assumptions on the customer's BAU use of grid and self-generation, Multi Year Tariff Order (MYTO) tariffs from the DisCO projected over the project lifetime, among others. Section 3.1.3 is a detailed list of the modelling inputs including reference dates since some inputs are variable with time.

STEP

2

We developed an annual load profile for each customer using data logged for one month at the customer's site. The load profile was an input for both the technical modelling in HOMER to size a DER for the site (see Task 2 Report for more details), and the economic model for computing revenues for Daystar and DisCos, where we also used HOMER simulated dispatch data for efficiently serving the load profile between the DER and the grid.

STEP

3

RMI developed multiple technical scenarios with the guidance of the Daystar engineering team for designing a suitable DER for each site based on the site's load profile and expected grid availability. We input the resulting DER system size into the economic model including solar PV, lithium-ion batteries, a diesel or gas generator, estimated annual diesel or gas consumption and generator run hours. Coupled with the component costs, the model could compute the system costs and economic outcomes for each party.

STEP

4

The C&I utility enabled DER business model entails the developer paying for grid upgrades to support improved grid reliability, for which the developer takes debt payment in the form of deductions from the DisCO's monthly collections from the site. The DisCos proposed charging a premium fee from the DER customers, additional to the MYTO tariff, to support grid upgrade cost repayments while retaining enough revenue for their other operational costs. The premium fee calculation that RMI and the DisCos agreed to is explained below.

The premium fee (in Naira per kWh) is the sum of:
[REDACTED]

The premium fee is designed with a component of OPEX cost to ensure that the DisCos have adequate resources prioritized to the C&I customers and can guarantee the grid reliability agreed to in the tripartite contract.



3.1.2 FINANCIAL MODELLING APPROACH

RMI developed a financial model using the bundled project revenues, capital requirements, operational costs, and financial assumptions from the Daystar team, to test Daystar's capacity to service debt

deployed in developing the DER projects. The key assumptions are listed in Table 26 and the financial model is included in the Task 3 close-out package.

Table 26: Financial modelling assumptions

MODELLING INPUT	ASSUMPTION	SOURCE
Debt Share of CAPEX	[REDACTED]	Daystar capital structure
Cost of Debt	[REDACTED]	Daystar reported
Debt Service Coverage Ratio (DSCR)	2x	Nigeria estimate from news coverage ^{vi}

According to Fitch Ratings, a minimum DSCR of 1.2x as required for investment-grade solar projects, while Nigerian news agencies report that local lenders require a minimum DSCR of 2x. Considering the impact of foreign exchange (forex) risks highlighted in the sensitivity analysis section in this report, we developed the financial model to assess the viability of Daystar meeting the debt requirements of Nigerian lenders as a funding option that hedges against forex risks.



^{vi} <https://punchng.com/why-banks-wont-give-you-loan/#:~:text=Nigerian%20banks%20often%20like%20to,no%20plans%20of%20repaying%20loans.>



3.1.3 MODELLING INPUTS AND SOURCES

ECONOMIC MODELING – GENERAL

	MODEL INPUT/ ASSUMPTION	DESCRIPTION/SOURCE/COMMENT
PROJECT DEVELOPMENT COST		
Project preparation	[REDACTED]	E.g., for roof assessment, permit cost. From discussion with Daystar
	[REDACTED]	For sites with power systems bigger than 1MW. From discussion with NERC
Customer self-generation cost	[REDACTED]	From discussion with Daystar as of August, 2023 [REDACTED]
Solar CAPEX	[REDACTED]	Includes panel, mounting structure, installation, balance of system. From discussion with Daystar (The panel itself is [REDACTED])
Solar lifespan	20 years	From discussion with Daystar
Battery CAPEX (Lithium-ion)	[REDACTED]	From discussion with Daystar
Battery lifespan (Lithium-ion)	10 years	From discussion with Daystar
Diesel CAPEX	[REDACTED]	From discussion with Daystar
Diesel lifespan	[REDACTED]	From discussion with Daystar
Diesel fuel	[REDACTED]	From discussion with Daystar as of August, 2023
Inverter CAPEX	[REDACTED]	From discussion with Daystar
Converter lifespan	15 years	HOMER default
Solar O&M	[REDACTED]	From discussion with Daystar
Battery O&M	[REDACTED]	From discussion with Daystar
Diesel O&M	[REDACTED]	From discussion with Daystar
Insurance	of equipment capex, per year	From discussion with Daystar
Diesel cost increase	12% per year	Reflecting the average 10-year inflation rate
O&M cost increase	8% per year	The average of USD and NGN inflation rates
Developer cost of debt	[REDACTED]	From discussion with Daystar
Developer cost of equity	[REDACTED]	From discussion with Daystar
Developer cost of debt	[REDACTED]	From discussion with Daystar



	MODEL INPUT/ ASSUMPTION	DESCRIPTION/SOURCE/COMMENT
Developer cost of equity	[REDACTED]	From discussion with Daystar
Project debt and equity share	[REDACTED]	From discussion with Daystar
Developer nominal WACC	[REDACTED]	From discussion with Daystar
Customer nominal discount rate	[REDACTED]	Assumed to be at the same level as the developer's WACC
NGN inflation rate	12%	Average Naira inflation over last 10years.
Change in exchange rate	5% per year	Same assumption as in the MYTO model
Developer's target IRR	[REDACTED]	This refers to the developer's target returns from the project. This is used to determine what the tariffs should be to give Daystar their target returns. From prior discussion with Daystar

MODELING – CUSTOMER/SITE-SPECIFIC

	MODEL INPUT/ ASSUMPTION	DESCRIPTION/SOURCE/COMMENT
GRID UPGRADE		
Grid upgrade capital cost	Variable for each site	Informed by Afry's grid upgrade requirement study and assessment
Cost of debt for grid upgrade	[REDACTED]	Same as developer's cost of capital, as Daystar will finance the upgrade
tenor for grid upgrade (to DisCo)	Variable from 1 year to 5 years	Negotiable between the DisCo and Daystar based on site circumstances
MYTO Tariff through 2028	Variable	Based on MYTO models shared by DisCos and the customer's tariff class. Reference date August, 2023
Increase in MYTO tariffs after 2028	12% per year	Reflecting the inflation rate
Customer DisCo tariff class without DER	Variable	Based on each customer's operation size and billing from DisCo
Customer DisCo tariff class with DER	Variable	Based on each customer's operation size and billing from DisCo
DisCo Nominal WACC	[REDACTED]	RMI assumption (based on DESSA work)



3.2 MODELLING RESULTS

KEY TAKEAWAYS

- RMI completed economic analysis for 22 shortlisted sites, then two of these customers were deprioritized for further analysis due to low interest from the customers in signing long-term contracts. Our analysis shows that for 17 out of 20 customers, the proposed C&I business model offers energy cost savings for the customers and can improve DisCo profitability.
- The main drivers for the economic outcomes include customer energy demand, hours of operation and current grid consumption.
- We also conducted sensitivities analysis on key variables affecting system design, project contractual terms and macro risks. We found that economic outcomes are particularly sensitive to DER component CAPEX, diesel price and foreign exchange rate. With suitable market conditions, some of the less promising results can become very attractive to customers and DisCos.
- The financial analysis suggests that Daystar can meet the minimum DSCR requirement of 2x by Nigerian lenders and achieve profitability for equity stakeholders. Daystar also is financially capable of deploying multiple projects simultaneously.

3.2.1 ECONOMIC MODELLING RESULTS SUMMARY

The economic model RMI developed runs based on the objective of ensuring that Daystar as the financing implementation partner, achieves their target Internal Rate of Return (IRR) of [REDACTED].

Though we completed preliminary analysis for 22 sites, two customers were deprioritized for further analysis due to the customers' low interest in long-term contracts with DisCos under the proposed 10-year tripartite agreement for the C&I DER business model. Table 27 below is a summary

of the resulting economics for 20 customers and their respective DisCos, and the capital cost (CAPEX) requirement from Daystar for each customer's DER solutions. The table is ranked in order of peak demand for each site, starting with the sites with the highest demand. See Section 3.1.3 for a detailed list of the modelling inputs and assumptions. RMI also included the detailed descriptions for the characteristics of each site in Section 2 above.



Table 27: Summary of the economic impact of the DER projects

COMPANY ^{vii}	CUSTOMER PEAK DEMAND (KW)	CUSTOMER ENERGY COST SAVINGS (%)	DISCO PROFITABILITY GROWTH (%)	CAPEX (\$)
[Customer 1]	5,798	44	100	15,317,928
[Customer 2]	3,439	28	93	6,223,600
[Customer 3]	2,981	37	1,022	8,948,908
[Customer 4]	1,384	40	226	4,487,536
[Customer 5]	676	42	831	1,904,260
[Customer 6]	573	34	359	863,312
[Customer 7]	396	(35)	(14)	435,188
[Customer 8]	373	15	150	959,612
[Customer 9]	257	44	100	700,784
[Customer 10]	255	(3)	10	534,068
[Customer 11]	247	21	27	707,636
[Customer 12]	209	8	41	426,776
[Customer 13]	173	37	261	317,228
[Customer 14]	165	19	8	439,100
[Customer 15]	164	12	44	420,644
[Customer 16]	158	12	(19)	115,964
[Customer 17]	93	(27)	(46)	131,924
[Customer 18]	80	16	113	108,260
[Customer 19]	77	28	60	142,352
[Customer 20]	70	5	36	113,156
Total Capex Required				43,298,236
Total Expected Solar Capacity Installation: 27 MW				

^{vii} Customers here are numbered from highest peak demand to lowest, same as in Table ES1.

The table is highlighted to show the most favorable economic outcome for each respective party in green, least favorable in red and average favorability in orange and yellow. For example, the sites with the highest customer energy cost reductions are those highlighted green in the “customer energy cost savings” column, while the least cost projects to implement are those highlighted green in the “CAPEX” column.

We identified multiple drivers that influenced the economic outcomes in the table above. Below are the key takeaways from the summary table.

1 IMPACT OF THE CUSTOMER SITE SIZE (PEAK DEMAND)

The six largest sites with a peak demand higher than 500KW showed the highest economic viability for all parties involved, with 38% average energy cost savings for the customers, and over 400% average profitability growth for the DisCos. For Daystar, they represent 83% of the total solar capacity (22.5MW out of 27MW) needed to deploy the designed DERs for all 20 sites and require 87% of the total project CAPEX.

The high economic viability is driven by the sites’ high energy consumption throughout the day that is expensive to sustain with diesel or gas self-generation, resulting in significant energy cost reduction for the customer and high energy consumption from the grid and DER with substantial revenue and profitability benefits for the DisCos and Daystar.

2 IMPACT OF “GRID PRIORITY HOURS” ENERGY CONSUMPTION

Four additional sites with an average peak of 200KW show similarly high economic viability for all parties. These are [REDACTED]. The driver behind the high economic performance of these sites is their overall high energy consumption throughout the day including in grid priority hours in the evening, early morning, and nighttime. [REDACTED] for example, consume little to no

power at night, which is a main driver for the poor economic benefits for the customers and DisCos. Coupled with their lower peak demand (averaging 80KW) and overall energy consumption, they are among sites with the lowest viability.

3 IMPACT OF BAU GRID CONSUMPTION

Sites with high current grid consumption like [REDACTED] also showed little or no DER economic benefits for the customers and DisCos. This is driven by consuming most energy during the day such that replacing that consumption from the grid with DER lowered DisCo revenue. In addition, consuming mostly grid power in the BAU scenario is the cheapest option for customers such that deploying a DER raises the overall cost of energy. The main incentive for these customers’ interest in the DER business model is reliability improvements in power supply since the grid in Nigeria is generally unreliable.

3.2.2 SENSITIVITY ANALYSIS RESULTS SUMMARY

RMI performed sensitivity analysis using modelling outcomes and discussions with Daystar, customers, and the DisCos to identify key variables that affect the project economics for different parties involved in the project. The sensitivity analysis is categorized into variables that affect system design, project contractual terms and macro risks.





SYSTEM DESIGN SENSITIVITY ANALYSIS



1 COST OF BATTERIES

We used \$660 per kWh as the battery cost in the base economic model for the results shown in Table 27 because it was the prevailing average price in the supplier quotations Daystar acquired in 2023. Since the initial battery cost assumption the Daystar team shared from previous procurements was [REDACTED] (2022 data), we tested [REDACTED] for sensitivity analysis, assuming that battery prices will continue to drop in Nigeria as the DER sector grows.

The battery cost of \$900 increases the customer blended tariff by an average of 8% which is significant for sites such as [REDACTED] and [REDACTED] that have marginal customer energy cost savings at the lower battery price of [REDACTED]. If the battery cost is [REDACTED], [REDACTED] would experience an increase in their energy costs from the current business as usual of 2% and 3% respectively, rather than getting energy cost savings from the DER business model.

However, at the battery cost of [REDACTED] per kWh the customers would have higher energy cost savings. For example, this moved [REDACTED] economics from a 3% increase in customer energy cost under the [REDACTED] assumption to a 7% energy cost saving. This battery cost also reduces Daystar's CAPEX requirements for developing the DERs from \$43.3 million to \$36 million.



2 DIESEL GENERATOR ELIMINATION FROM THE DER DESIGN

(the customer can choose to continue using existing generators as back-up)

The technical model for each site includes a diesel generator to guarantee the contractual system reliability with backup for the solar-battery system and grid as needed. However, some customers

such as [REDACTED] expressed interest in keeping their onsite generators as back-up rather than Daystar buying a new generator (which adds to the CAPEX and leads to a higher blended tariff outcome). We carried out sensitivity analysis for a no-generator DER design, and it resulted in a 17% average reduction in both customer blended tariff and CAPEX requirement from Daystar. Some sites that benefit most from this design option are listed in Table 28 below. It is therefore beneficial for Daystar and the customers to collaborate on using available assets onsite and lower project costs for both parties.

Table 28: Sensitivity of customer energy cost savings to diesel generator in DER design

CUSTOMER	ENERGY COST SAVINGS (%) WITH DIESEL GENERATOR	ENERGY COST SAVINGS (%) WITHOUT DIESEL GENERATOR
[REDACTED]	5	33
[REDACTED]	(27)	1
[REDACTED]	(3)	11

PROJECT CONTRACT TERMS SENSITIVITY ANALYSIS

1 MATERIALIZED LOAD

The tripartite contract includes a minimum energy consumption requirement from the customer for the DER priority hours to manage Daystar's financial risk of low revenue collection after investing in DER assets at the site. The base economic model assumption is that the customer consumes 100% of the forecast energy demand during the 6 DER priority hours from 9am to 3pm. We completed sensitivity analysis to assess the impact of lower materialized load on Daystar's target IRR and the customer's blended tariff to facilitate negotiations between Daystar and the



customer on the minimum energy consumption included in the contract, specifically for the Wood Factory as a fast-tracked implementation demonstration site.

Table 29 is a detailed summary of the variation in Daystar's IRR and customer blended tariff for [REDACTED]. If the materialized load is 80% rather than 100%, Daystar's IRR would decrease from [REDACTED] to retain a competitive customer blended tariff of 169 Naira per kWh. However, if Daystar retained the target IRR of [REDACTED] the customer's blended tariff would rise to 205 N/kWh, reducing their overall energy cost savings from the DER business model from 44% to 32%. The Daystar team used this analysis to determine the minimum energy consumption included in [REDACTED] tripartite contract and can continue to use the sensitivity analysis process to develop win-win contract terms and arrangements for the rest of the sites.

Table 29: Impact of materialized load on Daystar IRR and customer blended tariff

MATERIALIZED LOAD	DAYSTAR IRR (BLENDED TARIFF N 169)	BLENDED TARIFF N (IRR [REDACTED])	CUSTOMER SAVINGS
100%	[REDACTED]	169	44%
90%	[REDACTED]	185	39%
85%	[REDACTED]	195	35%
80%	[REDACTED]	205	32%

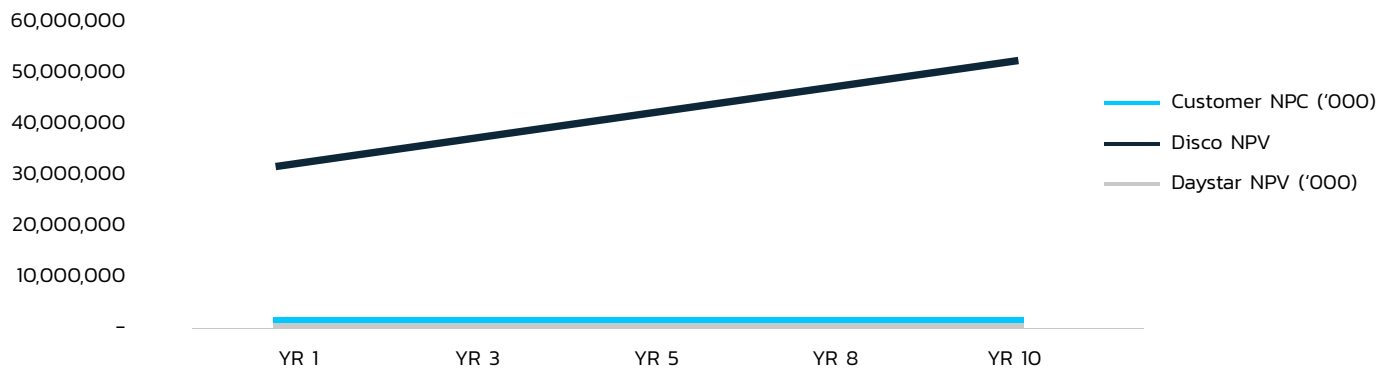
2 GRID UPGRADE REPAYMENT PERIOD

Daystar will finance the upfront capital cost for the grid upgrades to support improved grid reliability and take debt payment in the form of deductions from the DisCo's collections from the site. The debt terms are reflected in the tripartite agreement with a specified repayment tenure. RMI completed sensitivity analysis for [REDACTED], the site with the highest grid upgrade costs from the network assessment consultant's study and reports (grid upgrade recommendations were also validated by DisCo), to facilitate contract negotiations between Daystar and the DisCo since discussions with both

parties highlighted conflicting interests.

We varied the debt repayment tenure to evaluate the impact on the DisCos, Daystar and customer's economics from the project. Figure 29 shows that the debt repayment tenure doesn't impact the customer's energy cost savings (measured in Net Present Cost) or Daystar's profitability (measured in Net Present Value) from the project. However, the DisCo's profitability ((measured in Net Present Value) varies significantly with changes in debt tenure.

Figure 29: Impact of grid upgrade cost debt tenure on DisCo, customer, and Daystar economics

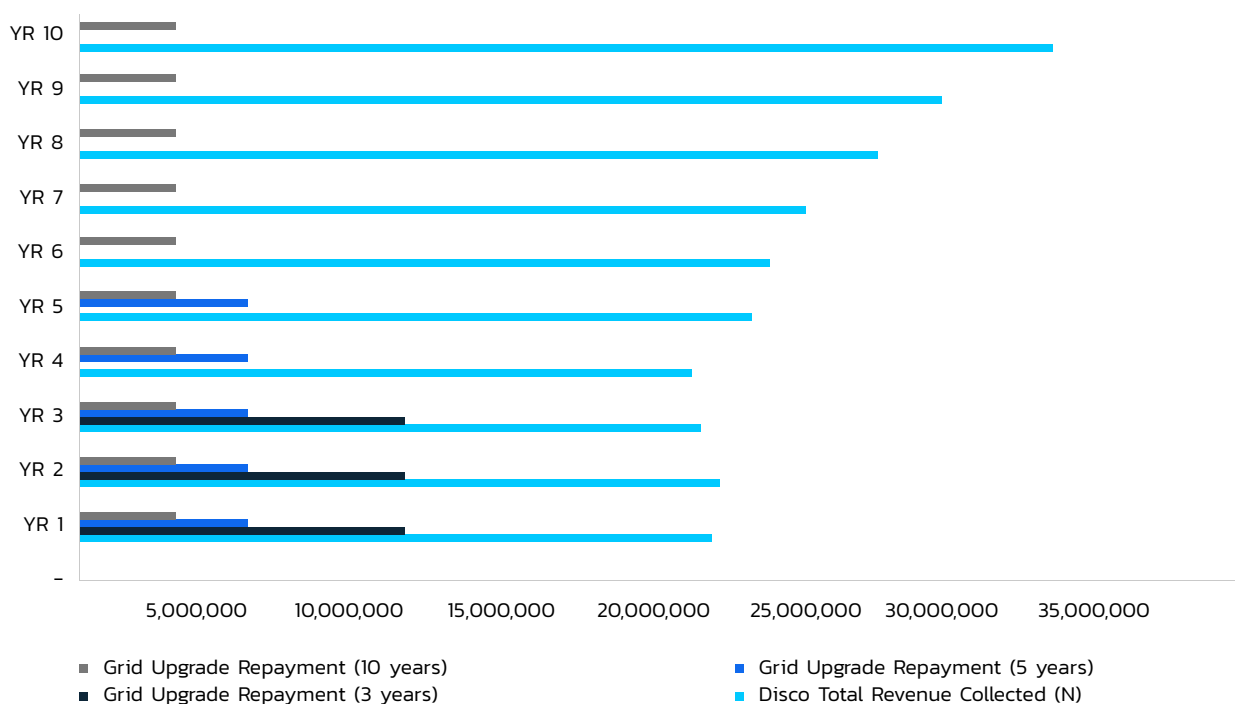


DisCos prefer the longest possible tenure of 10 years (project life) to minimize the monthly debt repayment deductions and retain revenue for other grid operation costs. Daystar on the other hand prefers the shortest possible tenure (1 year) to minimize the default risks associated with on-lending capital from their financiers and manage the opportunity cost of investing grid upgrade capital into other projects.

annual revenue to debt payments considering a 10-year, 5-year and 3-year debt tenure. A longer debt tenure gives the DisCo better debt service coverage (in this case the ratio of revenue collected by Daystar on behalf of the DisCo to the debt payment amount). This lowers the DisCo's risk for defaulting on debt payments in potential scenarios like grid outages reducing customer grid consumption and subsequent revenue to the DisCo.

Figure 30 shows a comparison of the DisCo's

Figure 30: Debt service coverage over 10, 5 and 3-year repayment tenures





These figures were presented to the Daystar and DisCo teams resulting in agreement on varying the tenure to match circumstances for each customer site by adopting a 4-year tenure for [REDACTED] as goodwill. Going forward, Daystar and DisCos should evaluate and align grid upgrade repayment period (considering 1–5-year tenures) on a case-by-case basis, balancing each team’s preferred terms and concerns.

MACRO RISKS SENSITIVITY ANALYSIS

1 FOREIGN EXCHANGE RATE

Nigeria recently voted in a new president whose administration immediately changed the foreign exchange policy from central bank to market determined exchange rates. The economic model was previously developed (2022 to early 2023) under the central bank determined dollar exchange rate of [REDACTED] and updated later in 2023 to the current market determined rate [REDACTED]. We completed sensitivity analysis to assess the impact this change had on the customer tariff and Daystar’s CAPEX requirements.

The analysis showed an average increase in customer tariffs and Daystar CAPEX of 27% and 40% respectively due to the rise in exchange rate assumption [REDACTED]. For some customers listed in Table 30 below, the exchange rate change shifted the savings from having a DER onsite to an increase in their energy costs.

Table 30: Impact of exchange rate on customer energy cost savings

CUSTOMER	ENERGY COST SAVINGS (%) [REDACTED] NAIRA EXCHANGE RATE	ENERGY COST SAVINGS (%) [REDACTED] NAIRA EXCHANGE RATE
[REDACTED]	(35)	8
[REDACTED]	(27)	19
[REDACTED]	(3)	33

Forex is a high risk for scaling the C&I business model since most DER capital in Nigeria is foreign and dollar denominated. Development financial institutions should therefore prioritize financing solutions that stimulate local currency investment in renewable projects in Nigeria as a long-term DER market hedge against forex risks.

2 DIESEL PRICE

Daystar reports that the price of diesel rose from about 260 Naira in 2021 to over 800 Naira in Lagos and 850 Naira in Abuja in 2023. We completed sensitivity analysis to test the impact of further increase to [REDACTED] by the time Daystar deploys DERs at all the sites, on the customer blended tariff and energy cost savings since they use diesel for self-generation alongside current unreliable grid supply.

The increase in diesel price increased the customer’s blended tariff by only about 1% since the DER model uses mostly solar, battery and grid to power the sites. However if the customers retained their business as usual of grid backed up by diesel generation, their energy costs would significantly increase. At the diesel price of [REDACTED] the average customer energy savings with the DER would increase by 71% compared to the base economic model with diesel price at [REDACTED]. The DER business model therefore enables customers to manage their exposure to future diesel price fluctuations.

3.2.3 FINANCIAL MODELLING RESULTS SUMMARY

The financial model shows that over the 10-year project life, Daystar would maintain a 2.8x average Debt Service Coverage Ratio (DSCR), well above the global solar project and local lender requirements of 1.2x and 2x respectively. Daystar’s equity shareholders would have a levered IRR of [REDACTED] almost twice the target unlevered IRR

of [REDACTED].

We also completed sensitivity analysis to assess the impact of cost and CAPEX share of debt on the levered IRR summarized in Table 31 below. Raising the cost of debt from [REDACTED] 8% to 20% would reduce the levered IRR from [REDACTED] almost as low as the unlevered IRR of [REDACTED]. However, the DSCR would still meet the 2x local lender requirement.

Utilizing more debt capital by increasing the debt portion of CAPEX from 67% to 80% would raise the levered IRR to [REDACTED] with an average DSCR of 2.27x.

Table 31: Impact of cost and capex share of debt on levered IRR

		PROJECT DEBT SHARE		
		67%	75%	80%
COST OF DEBT	8%	[REDACTED]	[REDACTED]	[REDACTED]
	10%	[REDACTED]	[REDACTED]	[REDACTED]
	12%	[REDACTED]	[REDACTED]	[REDACTED]
	15%	[REDACTED]	[REDACTED]	[REDACTED]
	20%	[REDACTED]	[REDACTED]	[REDACTED]

Overall, the project economics show potential to achieve both profitability for equity shareholders and sustainable debt repayments for lenders.





DAYSTAR FINANCING REQUIREMENTS AND SOURCES OF CAPITAL

Daystar states that, as of the compilation date of this report in August 2023, they have adequate capital required to deploy all 20 DER projects with the financial structure in Table 26 above. Regarding financing options for scaling the business model beyond the 20 sites, Daystar believes the acquisition by Shell provides access to substantial financial backing which can further unlock more external capital such as debt instruments, especially with the above financial assessment showing that the project portfolio has sustainable debt servicing capacity.

RMI mapped out available sources of scaling capital and identified multiple development financial institutions (DFIs) and nonprofits such as the World Bank and Rockefeller Foundation, who are funding initiatives for derisking DER projects to leverage private capitals. We found that private sector investors have high risk perception given

the low maturity of the financial market in Nigeria and the lack of investment risk management mechanisms beyond public sector support. Hence, private capital sources from both equity and debt investors are very limited.

Cygnus, an investment banking and asset management firm focusing on emerging economies, specifically highlighted foreign exchange risks in Nigeria as a key challenge for investing in DER projects. They prioritize ticket sizes in the \$10m to \$20m range which would be ideal for developing portfolios of C&I DER projects. Cygnus also pointed out the limited sources of equity to match their debt investments for a viable project capital split. They therefore underscored the development of cheap forex risk hedging mechanisms as a key step in unlocking more capital from both equity and debt investors for the DER sector in Nigeria.

3.3 SCALING IMPACTS

KEY TAKEAWAYS

- We estimated that the utility-enabled business model has potential to scale to 170,000 C&I customers across 11 DisCo service territories, representing a market of 3,300 MW of solar capacity and \$6.5 billion of capital investment.
- Daystar can be the front-runner in capturing the C&I DER market. In a conservative scaling scenario, Daystar is capable of developing 36 projects per year totaling 17 MW solar per year.

POTENTIAL ADOPTION THROUGH 2030

RMI used several parameters, including current DisCo customer counts and estimated customer demand, to estimate the scaling potential of the utility-enabled DER business model in Nigeria. viii Companies typically categorized by DisCos

as maximum demand (MD) customers would be a strong candidate for a utility-enabled DER solution, as most of these customers already heavily utilize backup generators. In the scaling scenario, we assume 100% adoption among MD



customers. In addition, we assume that a potential adoption rate of 5% among other C&I customers represents the larger non-MD customers.^{ix} We estimated the market size for the business model assuming a conservative average DER system of 20 kW that is more typical of small non-MD sites across all potential C&I DER customers.

From these assumptions, we estimate that across the 11 DisCo service territories there are approximately 170,000 C&I MD and non-MD customers who may be appropriate candidates

for a DER solution through the utility-enabled C&I business model. This would represent a total commercially viable market across Nigeria of approximately 3,300 MW of solar capacity and \$6.5 billion of capital investment. However, it will require time for the market to scale across all these potential customers. In this adoption estimate scenario, we expect that the average project size will decrease over time as the business model expands to customers with lower DER capacity needs. Table 32 shows the number of MD and non-MD customers across DisCo territories.

Table 32: Number of C&I customers across DisCo territories

ELECTRICITY DISTRIBUTION COMPANY (DISCO)	NUMBER OF MD C&I CUSTOMERS	NUMBER OF NON-MD C&I CUSTOMERS	POTENTIAL DER MARKET SIZE (MW) ^x
Abuja	6,070	121,426	243
Benin	7,518	163,376	314
Enugu	8,288	144,750	311
Eko	11,332	192,959	928
Ibadan	18,041	567,342	161
Ikeja	7,874	334,249	156
Jos	3,631	88,194	103
Kaduna	3,185	92,006	420
Kano	2,566	51,903	492
Port Harcourt	5,541	76,154	187
Yola	1,683	39,752	73
Total	75,729	1,872,112	3,387

We anticipate that Daystar will implement some of the projects de-risked through this study by the end of 2023, before completing the full set of 20 projects in 2024. For near-term scaling, the subset of high power demand C&I customers that are on feeders with lowest reliability have highest economic attractiveness.

^{viii} Customer counts were sourced from NERC Customer Counts in the MYTO model (2019).

^{ix} While not a firm cutoff, most MD customers tend to be larger than roughly 50 kW.



SCALING IMPACTS ON DAYSTAR'S BUSINESS

RMI used Daystar's current operations scale and portfolio size data to estimate their scaling scenarios from the 20 DER sites evaluated under this project to new sites across Nigeria. We estimate a conservative scaling scenario of 36 new DER customer sites per year with their current operation size of [REDACTED] and an optimistic scenario of 72 sites per year assuming they doubled the operation size.

Under the conservative scenario where Daystar installs DERs for 36 new customers annually with a median estimated peak demand of 250KW^x and median installed solar PV capacity of 480KW, Daystar will develop about 17MW annually. The more optimistic scenario of doubling operations capacity and installing 72 DERs annually equates to over 34MW of solar PV capacity. Currently Daystar's portfolio is made up of 364 sites representing 54MW of installed PV capacity. With the estimated

C&I DER market size at 3,400 MW, Daystar has the opportunity to grow their operations and use their early adopter experience to own a significant share of the overall C&I DER market.

Daystar currently has an estimated 12.6 billion Naira invested in their installed portfolio of C&I projects. The 20 DER sites evaluated under this project require about 33.3 billion Naira in implementation capital. While Daystar has sufficient capital to implement the 20 DER sites, they will need to grow their capital significantly and fast to exploit the C&I utility-enabled DER market opportunity to meet either of the scaling scenarios of 36 or 72 new DER sites annually. RMI believes successful implementation of the 20 DER sites will support Daystar's fundraising efforts by providing proof of concept data points for customers to ramp up contracting interest, subsequently lowering investment risk perception for new capital.



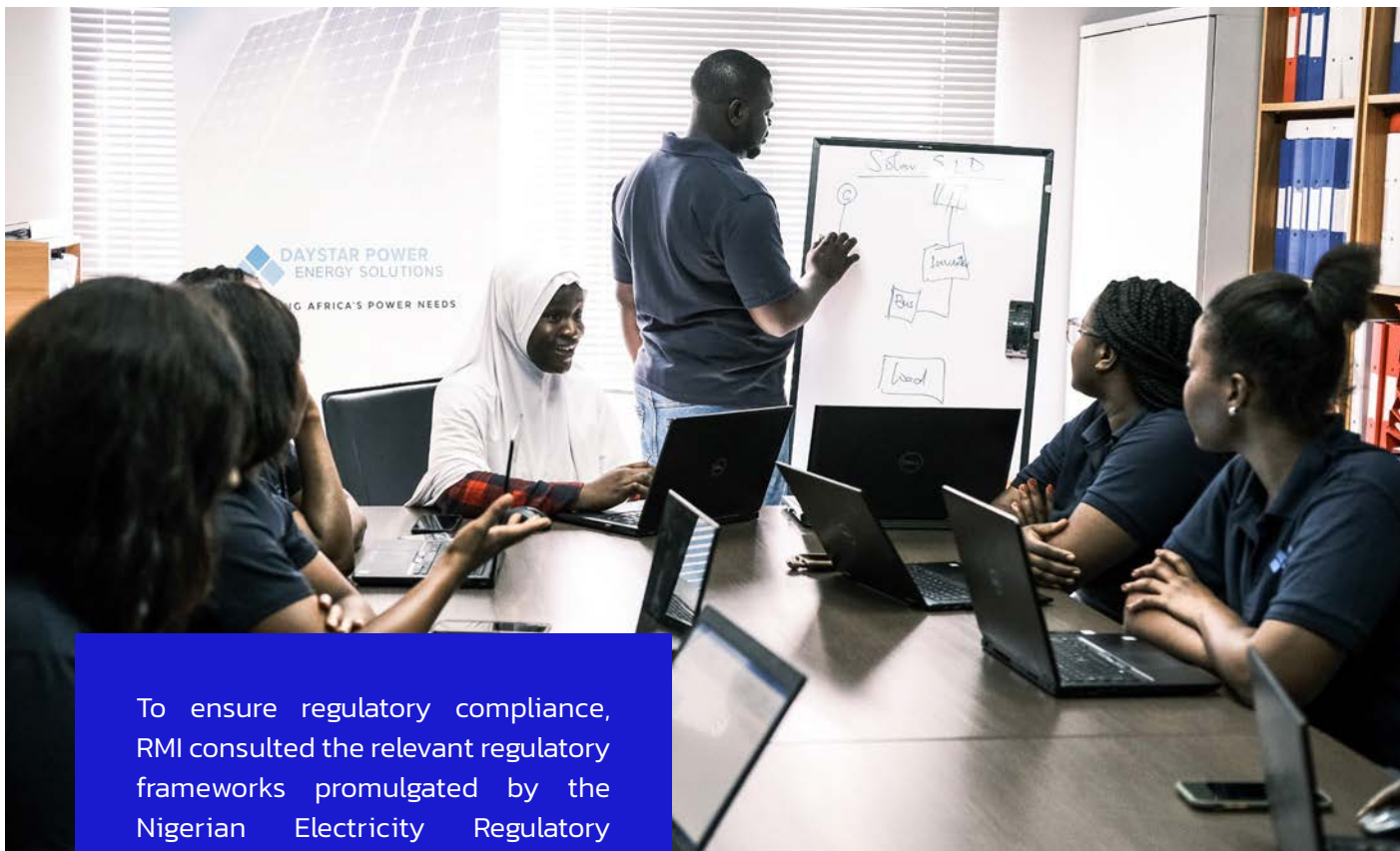
^x This assumes 100% adoption rate among MD customers and a conservative potential adoption rate of 5% among other C&I customers, along with the estimated demand per customer set conservatively at 20 kW.

^{xi} the median peak demand for the 20 sites RMI evaluated is 250KW and median solar PV capacity from the HOMER models for these sites is 480KW. We assume that early adopter customers will be similarly high energy consumers that incur high diesel costs to meet their energy needs.



04

REGULATORY REVIEW



To ensure regulatory compliance, RMI consulted the relevant regulatory frameworks promulgated by the Nigerian Electricity Regulatory Commission (NERC), mapped the utility-enabled business model to existing regulations or guidance to ensure adherence, and communicated transparently with regulators at NERC to ensure full regulatory compliance to unlock the most impactful business models and ensure long-term success.

In performing a regulatory analysis for these business models, RMI reviewed several regulations to ensure compliance, including the Independent Electricity Distribution Network Regulations (2012), the Eligible Customer Regulations (2017), the Embedded Generation Regulations (2012), the Feed In Tariff Regulation (2015), the Mini-Grid Regulation (2016), the Captive Generation Regulations (2018), the Bulk Generation Procurement Guidelines and Codes (2018), the Licenses and Operating

Fees Regulation (2010), the Application for Licenses Regulation (2010), Market Rules for the Nigerian Electricity Supply Industry (2014).
xii,xiii,xiv,xv,xvi,xvii,xviii,xix,xx,xxi

Upon review of these regulations, Daystar and RMI aligned and determined that the Mini-Grid Regulation and the Embedded Generation Regulation would be the guiding regulations for the business models based on comparability and fit between the intention of the regulations and the design of the business models. Specifically, the proposed business model for C&I customers seeks to improve customer electricity supply and quality with an interconnected distributed energy resource (DER), which most meets the description of a mini-grid in the Mini-Grid Regulation and renewable energy generation in the Embedded Generation Regulation. For projects with less than 1 Megawatt (MW) capacity, the Mini-Grid Regulation will be the guiding regulation and for project greater than 1 MW, the Embedded Generation Regulation is the guiding regulation.

4.1 REGULATORY PROCESS FOR THE DEPLOYMENT OF SOLUTIONS LESS THAN 1MW IN CAPACITY WITH THE NERC MINI-GRID REGULATION (2016) AS THE GUIDING REGULATION^{xxii}

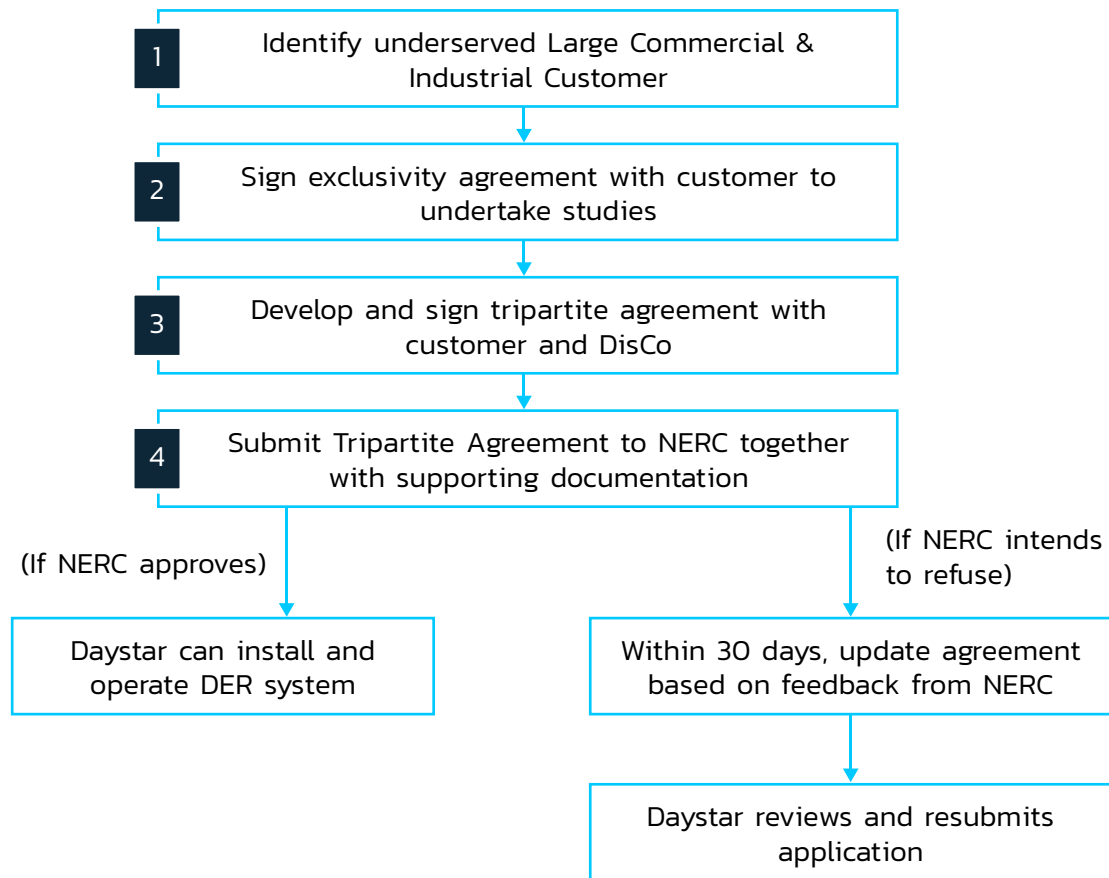
To deploy a solution less than 1 MW in capacity under this business model, the guiding regulation is the NERC Mini-Grid Regulation (2016). A solution less than 1 MW under this business model can be classified as an interconnected mini-grid. The diagram (Figure 31) below outlines the regulatory process Daystar needs to follow, as required by the

NERC Mini-Grid Regulation (2016). Table 1 further elaborates on the regulatory process step-by-step. Once NERC approves the Tripartite Agreement, Daystar can begin construction of the DER system and the Tripartite Agreement will be officially legally binding.^{xxiii}



- xii Nigerian Electricity Regulatory Commission, Independent Electricity Distribution Networks, NERC, 2012, [https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-\(Independent-Electricity-Distribution-Networks\)-Regulations-2012/?Itemid=591](https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-(Independent-Electricity-Distribution-Networks)-Regulations-2012/?Itemid=591)
- xiii Nigerian Electricity Regulatory Commission, Eligible Customer Regulation, NERC, 2017, <https://nerc.gov.ng/index.php/library/documents/Regulations/NERC-Eligible-Customer-Regulation-2017/>
- xiv Nigerian Electricity Regulatory Commission, Embedded Generation Regulations, NERC, 2012, [https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-\(Embedded-Generation\)-Regulations-2012/?Itemid=591](https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-(Embedded-Generation)-Regulations-2012/?Itemid=591)
- xv Nigerian Electricity Regulatory Commission, Feed in Tariff for Renewable Energy Sourced Electricity in Nigeria, NERC, 2015, <https://nerc.gov.ng/index.php/library/documents/Regulations/Feed-in-Tariff-for-Renewable-Energy-Sourced-Electricity-in-Nigeria.pdf>
- xvi Nigerian Electricity Regulatory Commission, Regulations for Mini-Grids, NERC, 2016, <https://nerc.gov.ng/index.php/library/documents/Regulations/NERC-Regulation-for-Mini-Grid/>
- xvii Nigerian Electricity Regulatory Commission, Permits for Captive Power Generation Regulations, NERC, 2018, <https://nerc.gov.ng/nercdocs/Regulation-for-Captive-Power-Generation.pdf>
- xviii Nigerian Electricity Regulatory Commission, Bulk Generation Procurement Guidelines & Codes, NERC, 2018, <https://nerc.gov.ng/index.php/component/remository/Tariff-Charges--and--Market-Rules/Tariff-Charges-and-Market-Rules/Bulk-Generation-Procurement-Guidelines--and--Codes/?Itemid=591>
- xix Nigerian Electricity Regulatory Commission, License and Operating Fees Regulation, NERC, 2010 <https://nerc.gov.ng/index.php/component/remository/Regulations/NERC-Licence-and-Operating-Fees-Regulation-2010/?Itemid=591>
- xx Nigerian Electricity Regulatory Commission, Application for Licences (Generation, Transmission, System Operations, Distribution & Trading) Regulations, NERC, 2010, <https://nerc.gov.ng/nercdocs/Regulation-for-the-Application-for-Licence.pdf>
- xxi Nigerian Electricity Regulatory Commission, Market Rules for the Nigerian Electricity Supply Industry, NERC, 2014 <https://nerc.gov.ng/index.php/library/documents/func-startdown/312/>
- xxii While we recommend deploying solutions less than 1MW in capacity with the NERC Mini-Grid Regulation (2016) as the guiding regulation, there is precedence that shows that the projects can be deployed without going through the mini-grid regulatory process and getting approval from NERC. In particular, this approach can be followed if there is minimal, or no network upgrades cost financed by Daystar.
- xxiii NERC approving the tripartite agreement is the equivalent of getting a permit for isolated mini-grids.
- xxiv NERC mini-grid online application portal – <https://mini-grid.nerc.app>
- xxv Nigerian Electricity Regulatory Commission Mini Grid MYTO Model 2021, NERC, 2021 <https://nerc.gov.ng/index.php/library/documents/Regulations/Mini-Grid-MYTO-Model-2021/>

Figure 31 and Table 33 Regulatory process to deploy solutions that are less than 1MW



NO	ACTION	DESCRIPTION
1	Identify underserved large commercial & industrial customer	Using the site selection criteria, Daystar should identify a suitable large commercial or industrial customer who fits the site selection criteria and is interested in the utility-enabled solution. Daystar should propose the project to the licensed distribution company (DisCo) that serves the customer or serves the customer's catchment area and get the DisCo's approval.
2	Sign exclusivity agreement with community (C&I customer) to undertake studies	Daystar can sign an exclusivity agreement for up to 12 months with the large commercial or industrial customer to conduct technical and feasibility studies for the solution. While this is optional according to the regulation, the mini-grid online application portal requires applicants to submit an exclusivity agreement.
3	Develop and sign tripartite agreement with customer and DisCo	Based on the solution's technical and financial design, Daystar should prepare a tripartite agreement with the details of the solution, ensure alignment with the DisCo and the customer on the terms and conditions and have all parties sign the agreement



NO	ACTION	DESCRIPTION
4	Submit Tripartite Agreement to NERC together with supporting documentation	Daystar should submit the tripartite agreement to NERC together with the supporting documentation described in 1.1 (below) as part of an application for NERC's approval. The application shall be addressed to the Secretary of the Commission, and delivered by hand or sent by regular mail or courier to the Commission's headquarters. The Agreement, which forms the application for the mini-grid, shall be signed and dated by Daystar. The application shall be submitted in three paper copies and an electronic version in Microsoft Office software format. Alternatively, Daystar can submit an application via the NERC mini-grid online application portalxxiv

4.1.1 SUPPORTING DOCUMENTATION NEEDED FOR NERC'S APPROVAL OF THE TRIPARTITE AGREEMENT

When requesting NERC's approval of the Tripartite Agreement, Daystar, as the Mini-Grid Operator, is required to submit the following documents to

receive NERC approval to install and commission a mini-grid system.

Table 34: Supporting document needed for NERC's approval in accordance with the Mini-Grid Regulation

NO	DOCUMENT(S)	DESCRIPTION
1	Certified copy of Certificate of Incorporation, Memorandum and Articles of Association, Deed of Partnership or Deed of Trust, as applicable	These documents prove that Daystar is a registered entity in Nigeria. The documents can be processed through the Corporate Affairs Commission (CAC)
2	Filled Standardized Spreadsheets for Tariff Calculation	Daystar is required to fit project tariffs to the standardized mini-grid MYTO tariff model and present it to NERC. The spreadsheet can be found on the NERC's websitexxv
3	Environmental and Social Management Plan (ESMP)	NERC does not require an ESMP, but this should be prepared and submitted as proof that the project complies with the existing environmental regulation.
4	Certified copy of Building Permit	A building permit is an official approval to proceed with a construction project. While it is a required document by NERC, people familiar with the matter posit that a lease agreement should be sufficient.
5	Power station layout drawings, which can be included in the tripartite contract.	



NO	DOCUMENT(S)	DESCRIPTION
6	Map with the position of power station and distribution network marked using indicators to distinguish single phase and three phase as well as medium voltage networks, which can be included in the tripartite contract.	
7	Lease Agreement, which can be included in of the tripartite contract, if applicable.	

4.1.2 MAJOR OBLIGATIONS IN ACCORDANCE WITH THE MINI-GRID REGULATION

Daystar is required to carry out its obligations in accordance with the Mini-Grid Regulation. The table below summarizes the major obligations

Table 35: Major obligations in accordance with the Mini-Grid Regulation

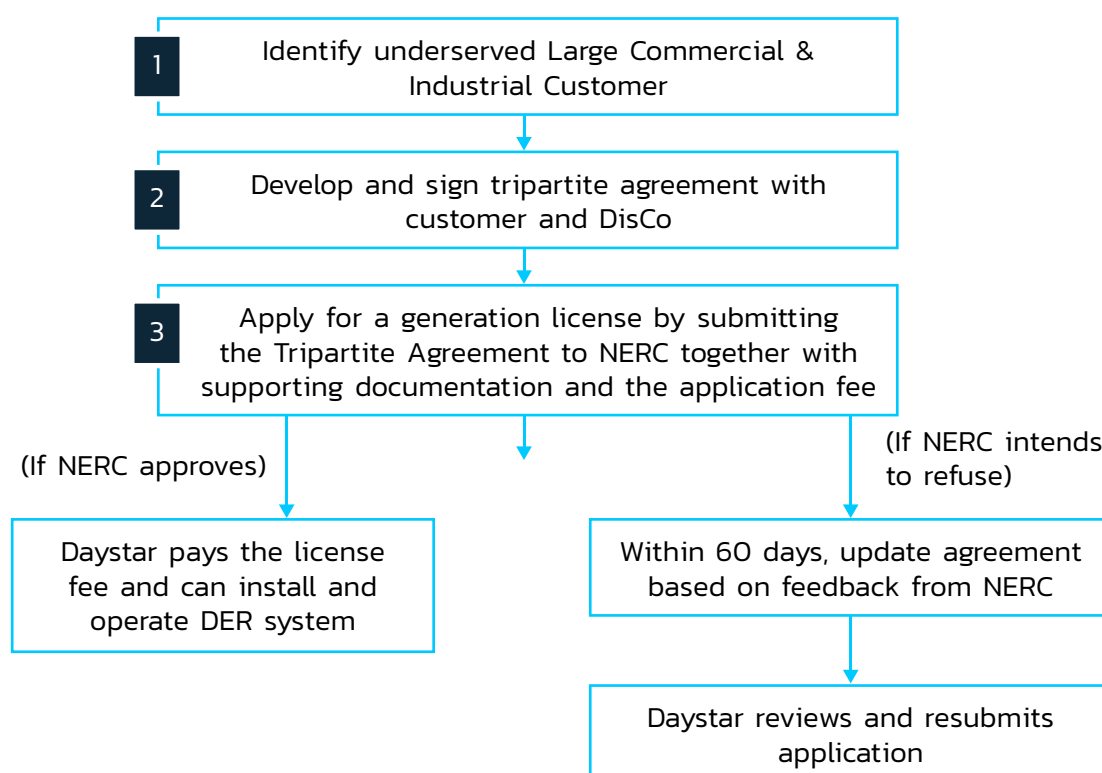
NO	OBLIGATION(S)	DESCRIPTION
1	Maintain Separate Accounts	Daystar is required to maintain a separate account for the mini-grid business and prepare accounting statements on the mini-grid business for each fiscal year
2	Periodic Tariff Reviews	Daystar is required to provide account information on the mini-grid system at least once every two years to allow NERC to review the mini-grid tariff. Daystar shall provide these reports in the form prescribed in Annex 4 of the Mini-Grid Regulation ⁵ . NERC can adjust the tariffs based on the mini-grid MYTO methodology inputs. The Mini-grid customer can also trigger the adjustments of tariff by requesting an inspection of accounts by NERC.
3	Installation and Maintenance	Daystar is required to install and operate the solution in compliance with the technical codes and standards approved by NERC, as well as the terms and conditions of the tripartite contract.
4	Safety and Environmental Protection	Daystar is required to comply with the safety guidelines prescribed in Annex 6 of the Mini-Grid Regulation ⁵ and existing environmental legislation
5	Dispute Resolution	Daystar is required to follow the Dispute Resolution Mechanism in Annex 10 of the Mini-Grid Regulation ⁵ for all disputes arising from or in connection with the Mini-grid. Disputes arising between the Daystar, the DisCo and the customer unable to be resolved by the parties shall be resolved by NERC through a dispute resolution counsellor (DRC) or a dispute resolution panel (DRP). NERC is amenable to the use of alternate dispute resolution mechanisms e.g., the expert determination process in the tripartite contract, as long all parties agree and sign-up to the process.

In addition, Daystar is required to install and operate this solution in accordance with good industry practice, standards set out by the Standards Organization of Nigeria and other best practices that Daystar typically meets as a DER developer.

4.2 REGULATORY PROCESS FOR THE DEPLOYMENT OF SOLUTIONS GREATER THAN 1MW IN CAPACITY WITH THE NERC EMBEDDED GENERATION REGULATION (2012) AS THE GUIDING REGULATION

To deploy a solution larger than 1 MW in capacity under this business model, the guiding regulation is the NERC Embedded Generation Regulation (2012). The diagram (Figure 32) below outlines the regulatory Daystar needs to follow, as required by the NERC Embedded Generation Regulation (2012). Table 36 further elaborates the regulatory process step-by-step. Once NERC approves the Tripartite Agreement and generation license, Daystar pays the license fee and NERC grants the license. Once this is done, Daystar can begin construction of the DER system and the Tripartite Agreement will be officially legally binding.

Figure 32 and Table 36: Regulatory process to deploy solutions with capacity larger than 1MW



NO	ACTION	DESCRIPTION
1	Identify underserved Large Commercial & Industrial Customer	Using the site selection criteria, Daystar should identify a suitable large commercial or industrial customer who fits the site selection criteria and is interested in the utility-enabled solution. Daystar should propose the project to the licensed distribution company (DisCo) that serves the customer or serves the customer's catchment area and get the DisCo's approval.
2	Develop and sign tripartite agreement with customer and DisCo	Based on the solution's technical and financial design, Daystar should prepare a tripartite agreement that contains the various network agreements, ensure alignment with the DisCo and the customer on the terms and conditions and have all parties sign the agreement
3	Apply for a generation license by submitting the Tripartite Agreement to NERC together with supporting documentation and the application fee	Daystar should apply for a generation license by completing the application form, submitting it together with the tripartite agreement and other supporting documentation (see 2.1 below) and paying a ₦70,000 processing fee to NERC. The application form can be found in Schedule 2 and the full list of documents needed for application in Schedule 1A and 1B in the Application for Licenses Regulation ⁹ . The application shall be addressed to the Chairman of the Commission and delivered by hand or sent by regular mail or courier to the Commission's headquarters. The application shall be submitted in three paper copies and an electronic version in Microsoft Office software format. If the application is successful, Daystar is required to pay a license fee of \$5,000.





4.2.1 SUPPORTING DOCUMENTATION NEEDED FOR APPLICATION FOR GENERATION LICENSE AND APPROVAL OF THE TRIPARTITE AGREEMENT

When applying for a generation license and requesting NERC's approval of the Tripartite Agreement, Daystar, as the Embedded Generator, is required to submit the application form and the following documents to receive NERC approval to install the embedded generation system. All supporting documents shall be submitted in two paper copies and one electronic version.

Table 37: Supporting document needed for NERC's granting of a generation license in accordance with the Application for Licenses Regulation

NO	DOCUMENT(S)	DESCRIPTION
1	Certified copy of Certificate of Incorporation, Memorandum and Articles of Association, Deed of Partnership or Deed of Trust, as applicable	These documents prove that Daystar is a registered entity in Nigeria. The documents can be processed through the Corporate Affairs Commission (CAC)
2	Off-take Agreement or Arrangement (Tripartite Agreement)	The tripartite agreement represents the off-take agreement and other network agreements.
3	Details on how effluents and discharges will be managed or Environmental Impact Assessment (EIA) Approval Certificate, or proof of submission and acceptance for processing of the EIA Report to the Ministry of Environment	NERC does not require an EIA report, but this should be prepared and submitted as proof that the project complies with the existing environmental regulation and should include a section on how effluents and discharges will be managed.
4	Registered Title Deed to Site, or Sale Agreement, or Deed of Assignment/Gift, or evidence of submission of a title deed to a relevant land processing agency (as applicable)	The lease agreement embedded in the tripartite agreement shall serve as the site permit.
5	Tax Clearance Certificate for immediate past three (3) years	The Tax Clearance Certificate issued by Federal Inland Revenue Service, showing assessment records of the past three years.
6	Ten-year Business Plan	A ten-year business plan that includes all the details found in Schedule 1F (2) of the Application for Licenses Regulation ⁹ .
7	Details of fixed infrastructure for generation assets following the requirements for applications for generation licenses. This can be included as part of the tripartite contract.	
8	Timelines for commissioning of the power plant and the date when different capacities of the plant will come into operation. This can be included as part of the tripartite contract.	
9	Financing Agreements or Letter to fund the project from financial institution. This can be included as part of the tripartite contract, or a separate document.	



Documentation required by NERC that may not be applicable include:

- A memorandum of understanding (MoU) with or Letter of intent from Engineering Procurement Contract (EPC) Contractor (if applicable).
- MoU with or Letter of Intent from the technical partner (if applicable).

4.2.2 MAJOR OBLIGATIONS IN ACCORDANCE WITH THE EMBEDDED GENERATION REGULATION

Daystar is required to carry out its obligations in accordance with the Embedded Generation Regulation. Table 38 below summarizes the major obligations.

Table 38: Major obligations in accordance with the Embedded Generation Regulation

NO	OBLIGATION(S)	DESCRIPTION
1	Annual Operating Fees	Daystar, as an embedded generation licensee shall pay 1.5% of the energy charges collected from the customer
2	Maintain Separate Accounts	Daystar is required to maintain a separate account for the embedded generation business
3	Prohibition from engaging in other Regulated Activities	Daystar shall not engage in the business of distribution, transmission, trading and system operations.
4	Installation and Maintenance	Daystar is required to install and operate the solution in compliance with the technical codes and standards approved by NERC, as well as the terms and conditions of the tripartite contract.
5	Dispute Resolution	Disputes arising between the Daystar, the DisCo and the customer unable to be resolved by the parties shall be resolved by NERC in accordance with the Dispute Resolution Procedure in Rule 43 of the Market Rules ¹⁰ through either a dispute resolution counsellor (DRC), a dispute resolution panel (DRP) or the applicable Dispute Resolution Procedure approved by the Commission, from time to time. NERC is amenable to the use of alternate dispute resolution mechanisms e.g., the expert determination process in the tripartite contract, as long all parties agree and sign-up to the process.
6	Renewal of License	Daystar shall apply for the renewal of the generation licence nine months before the expiration of the licence via the form specified in Schedule 4 of the Application for Licenses Regulation ⁹ .

In addition, Daystar is required to install and operate this solution in accordance with good industry practice, standards set out by the Standards Organization of Nigeria and other best practices that Daystar typically meets as a DER developer.



4.3 REVIEW OF PROBLEMS FACED DURING REGULATORY ASSESSMENT; LEGAL, REGULATORY AND INSTITUTIONAL CHALLENGES FACING THE BUSINESS MODEL; AND PROPOSED REMEDIES AND RECOMMENDATIONS

Based on discussions with NERC, RMI does not foresee any legal, regulatory, or institutional challenges that will wholly impede project development. That said, the business model faces unique legal, regulatory, and institutional uncertainties, mostly attributed to the fact that the business model has not been executed in the Nigerian Electricity Supply Industry (NESI) before.

The specific uncertainties facing the business models and proposed remedies are outlined below.

WIDE RANGE OF POWER NECESSITATING LEVERAGING MULTIPLE REGULATIONS

Large C&I customers have a power demand of ranging from tens of kilowatts to tens of megawatts. During our technical analysis and system sizing, the project team designed system capacities of greater than 1MW for certain projects. However, there is a system capacity cap of 1MW for systems to be deployed under the mini-grid regulation. To remedy this, RMI sent a memo to NERC to request a waiver or an extension of the 1MW cap for the projects to be deployed under the Mini-grid Regulations. However, NERC was unwilling to waive or extend the cap but suggested work-arounds like deploying multiple systems in a single facility and seeking multiple project approvals.

The RMI team also saw a fit between the business model for solutions for greater than 1MW capacity

and the solutions covered under the Embedded Generation model, although solutions deployed under the Embedded Generation Regulation have significant operating and licensing fees over the projects' lifetime.

CUSTOMER ARCHETYPE UNDER THE REGULATION

The target customer archetype under the Mini-grid Regulation is rural communities, i.e., "more than one customer". However, the large commercial and industrial customer is the target customer archetype for this business to be deployed under this regulation. NERC representatives affirmed that the critical requirement to deploy projects under this business model is to be under the capacity cap and this business model is suitable to be deployed under this regulation.

PROPOSED CHANGES IN THE MINI-GRID REGULATION

NERC released a consultation paper proposing changes to the Mini-grid Regulation. The key proposed change to the regulation is allowing for the submission of simultaneous applications for a portfolio of mini-grid sites. This change, if implemented, will support Daystar in rapid implementation of projects, allowing Daystar to seek NERC's approval for multiple projects under the Mini-grid Regulation at the same time.



4.4 NERC ALIGNMENT AND REGULATORY VERIFICATION

NERC is in support of the business model being deployed under the Mini-grid Regulation and Embedded Generation Regulation. NERC representatives affirmed in discussions that deploying this business model under these regulations is innovative, and they will support it. The business model meets the top priority of NERC which is to provide improved power quality to customers at a reasonable cost.

The project consulted with NERC multiple times at various stages of the project including an in-person discussion in July 2022 soliciting for guidance on key regulatory uncertainties. The project team also leveraged on extensive engagements with NERC during the development stage of this business model in 2021.

RECAP OF NERC GUIDANCE/FEEDBACK FROM MEETING:

+ Can NERC waive or extend the 1MW cap for the projects to be deployed under the Mini-grid regulations?

No, NERC will not extend the 1MW cap for the projects deployed under the mini-grid regulation. NERC is still willing to consider workarounds, such as deploying multiple systems in the same facility.

+ Can this business model be deployed under the Embedded Generation regulation?

Yes, NERC thinks deploying this business model under the embedded generation regulation is innovative and promising. NERC concedes that the licensing cost and process may be prohibitive but is willing to support it. NERC is also willing to create new regulatory processes to aid the quick implementation of projects, for example, a regulation allowing multiple project approvals and licenses to be sought concurrently.



05

CONTRACT DEVELOPMENT

To implement the proposed business model, C&I customers, Daystar and respective DisCos will enter into a tripartite agreement (also referred to as the “contract”), which is a critical element of project structuring and implementation.

As part of the feasibility study and project de-risking efforts, RMI worked closely with Daystar and DisCos and developed several versions of tripartite contract templates. This report describes the design and scope of the tripartite agreement, summarizes key contract terms and considerations, as well as feedback and takeaways from preliminary contractual negotiation with DisCos and customers.

In addition to the discussion in this section, we also prepared the following in Appendices: [REDACTED]

- Annex 5–B: Five versions of tripartite contract templates (with comments in the document in areas needing additional attention)

1

“MG-DPS-AEDC-Tripartite Power Contract Template-with Diesel”, which is suitable for customers with DER sizing up to 1MW in AEDC territory, and Daystar will invest in new diesel backup generators.

2

“MG-DPS-AEDC-Tripartite Power Contract Template-without Diesel”, which is suitable for customers with DER sizing up to 1MW in AEDC territory, and the customer will be responsible for procuring fuels and maintaining their diesel backup generators.

3

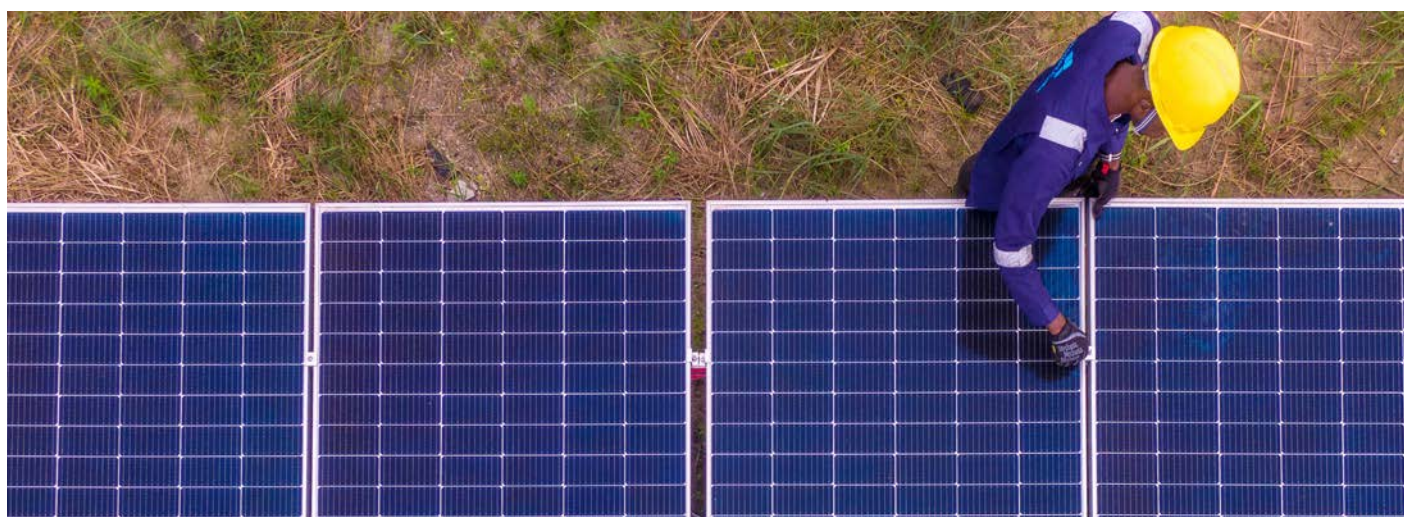
Power Producer-DPS-AEDC-Tripartite Power Contract Template” is suitable for customers with DER sizing above 1MW in AEDC territory.

4

“MG-DPS-IE-Tripartite Power Contract Template”, which is suitable for customers with DER sizing up to 1MW in IE and EKEDC territories.

5

“Power Producer-DPS-IE-Tripartite Power Contract Template” is suitable for customers with DER sizing above 1MW in IE and EKEDC territories.





5.1 THE DESIGN AND SCOPE OF THE TRIPARTITE AGREEMENT

KEY TAKEAWAYS

- Developing tripartite agreement template is a key element in preparing pipeline projects for implementation, and it requires thorough understanding of the business model, the respective business operation and priorities among each other, and significant alignment efforts especially between the DER developer and DisCos, which is often time-consuming.
- The templates developed are results of rounds of reviews and discussions with Daystar and DisCos' legal, project and technical teams. The templates offer solid basis that Daystar and DisCo can adjust and adapt per transaction as needed, and ensure transaction close for the various projects.

The agreement details the responsibility and arrangements, and governs the obligations among the customer, Daystar as the developer, and the DisCo. It also integrates pricing and cost analysis (from Task 2 and Task 3) in a fair, transparent manner. To develop the tripartite agreement, RMI built on experience from a previous USTDA-funded project—Distributed Energy Solutions Strategy for AEDC (DESSA) and had extensive engagement and discussions with DisCos and Daystar, while seeking guidance from NERC to ensure regulatory compliance.

To be comprehensive and cover the most relevant terms, we prepared several versions of tripartite contract templates that cater to regulatory requirements and specific customer and DisCo needs. For example, NERC has recommended leveraging the Minigrid Regulation for obtaining the necessary license for implementing the proposed business model, but the regulation only applies to DER systems that are smaller than 1MW in capacity. The team therefore developed another template suitable for larger systems, incorporating

regulatory requirements from the Embedded Generation Regulation (following NERC's guidance) and Daystar's existing Power-as-a-Service contracts. However, key contractual terms and core design rationale remain the same across different versions of the contract templates.

These templates are confirmed by Daystar and DisCos (AEDC and IE), having gone through several rounds of detailed legal reviews and edits. Through the project, Daystar and DisCos deepened understanding of the proposed business model and became familiar with their respective roles and responsibilities, and various arrangements among themselves. This will facilitate implementation of C&I DER projects and overtime, enable Daystar and DisCos to adapt and improve the templates.

Table 39 summarizes key contract clauses and the rationale behind the way they are designed. The team carefully proposed these with the intent that the terms create a contract that appropriately and fairly distributes responsibility and risk among the three parties involved.

Table 39 Summary of key contract clauses and rationale

ITEM	CLAUSES IN THE TEMPLATE	RATIONALE AND FURTHER CONSIDERATIONS
Contract Period	<ul style="list-style-type: none"> The template contract period is 10 years^{xxvi}. There are clear options to terminate the contract prematurely and to renew the contract. 	Considering solar PV typically has a 20-year lifespan, a longer contract period allows DER developers to distribute project costs over a longer time frame, reducing the customer's tariff and increasing their net savings.
Electricity Supply Obligations (Supply Hours)	<ul style="list-style-type: none"> Obligation to provide power is shared between the DER developer and the DisCo. <ul style="list-style-type: none"> DER Priority Hours: 9:00 AM – 2:59 PM, with 95% availability of supply Grid Priority Hours: 3:00 PM – 8:59 AM; availability of supply will be confirmed by DisCo The DER developer is responsible for backing up the DisCo's power supply to ensure the customer has reliable power as much as possible (namely ensuring that the customer ends up with very high reliability monthly on average, such as 95% reliability). 	<p>Dividing supply obligations by hour of day ensures that the DER system does not need to be oversized to meet the customer's electricity needs during evening and night-time hours, while sufficiently utilizing low-cost solar generation during the day. It effectively reduces the cost of electricity supply to customers compared to the diesel alternative, and thus makes DER solutions more price competitive for customers who can be provided a relatively high number of hours of supply of electricity from the grid.</p> <p>The DER and Grid Priority Hours can be further aligned and agreed upon per transaction depending on the grid availability and commitment that the Disco can make. But the more DER Priority Hours overlap with solar generation hours, the better.</p>
Minimum Consumption	<ul style="list-style-type: none"> The contract provides for the DER developer and the C&I customer to agree upon a reasonable Minimum Consumption, which is the minimum amount of total kWh the C&I customer will consume or pay for every six months. Minimum Consumption levels proposed should be quantities of electricity that the C&I customer feels confident it will consume based on historical load data. 	<p>The intent of this clause is to provide assurance to the DER developer that the C&I customer does not plan to defect from the contract. A Minimum Consumption confirms that the C&I customer plans to continue to use electricity at similar levels as in the initial assessment (as materialized loads will greatly impact project economics). This discourages customers from opting to use an alternative energy source or from intentionally oversizing their systems, which would undermine the economics of the project for the DER developer and DisCo.</p> <p>The Minimum Consumption can be calculated on a six-month basis to account for seasonal fluctuations in the C&I customer's operations.</p>

^{xxvi} Currently, 15–20-year DER contracts are rare; 5–10-year contracts with renewal terms are more common. According to industry interviews, this is due to customers' reluctance to sign onto long-term contracts, in part due to historic price volatility. However, while the template Tripartite Agreement is intended to provide structure on how to calculate tariffs to give parties the ability to predict what tariffs and electricity costs will likely be, it also provides adequate flexibility to modify the tariff based on current market conditions to account for macroeconomic volatility.



ITEM	CLAUSES IN THE TEMPLATE	RATIONALE AND FURTHER CONSIDERATIONS
Necessary Grid Upgrades	<ul style="list-style-type: none"> The DisCo is responsible for making necessary upgrades to the distribution network, which the DER developer will help finance (and initially own the new assets). The DisCo will repay the DER developer for the financing of grid upgrades over an agreed period. We recommend repayment period of one to five years. Payment will be deducted from DisCo bill to DER developer (for grid electricity delivered) monthly. If the project is terminated prematurely before grid upgrade debt is paid off, DisCo shall repay any outstanding amount owe to the DER developer within 12 months. 	<p>Necessary grid upgrades prior to project implementation ensure the DisCo can achieve the agreed reliability standards. DER developer can include the grid upgrade capital cost in its project financing. The details of grid upgrades will be validated by the DisCo and listed out as a Schedule (or Annex) in the tripartite agreement.</p> <p>The DER developer and DisCos need to balance each other's interests and align on the repayment period on a case-by-case basis.</p>
Pricing	<ul style="list-style-type: none"> DER developer will sell electricity to the customer at a single Blended Tariff for all electricity consumed (from both DER system and the grid). The Blended Tariff is predefined and composed of the DER Tariff and the DisCo Grid Tariff. To provide stability and transparency, the Blended Tariff can only be adjusted due to changes in Market Conditions and changes in the DisCo Grid Tariff. DisCo will include a premium fee in the DisCo Grid Tariff, which will ensure the prioritization of the feeder for supply and maintenance. 	<p>Having one Blended Tariff that the customer pays for all electricity consumed makes billing straightforward for customers. It also avoids inappropriate incentives for the customer to change their consumption pattern that might undermine project economics.</p> <p>The DisCo Grid Tariff is intended to be tied to the Multi-Year Tariff Order (MYTO) and the specific Band will need to be confirmed per transaction with DisCo (we expect it will be Band A MD-1 for most customers). The premium fee is designed to support the DisCo to repay grid upgrade cost and incentivize additional efforts to prioritize the customer.</p>
Billings and Collections	<ul style="list-style-type: none"> DER developer responsible for billing the customer for all electricity received (from both DER system and the grid) and collecting the payment from the customer. DisCo will bill the DER developer for electricity it provides, then the DER developer will settle with DisCo for electricity received from the grid at the specified DisCo grid tariff, minus any project-related debts (e.g., grid upgrade repayment) the DisCo holds or incurs. 	<p>This gives the customer a single point of contact for all billing and collections: the DER developer. By deducting any debts the DisCo incurs from the amount the DER developer owes the DisCo for supply, the DisCo should never be required to transfer funds to the DER developer.</p>

ITEM	CLAUSES IN THE TEMPLATE	RATIONALE AND FURTHER CONSIDERATIONS
Tariff Adjustments	<ul style="list-style-type: none"> The Blended Tariff can be adjusted due to Market Conditions (e.g., inflation rate, diesel price, foreign exchange rate) exceeding the acceptable thresholds as defined in the contract, or due to changes in the DisCo Grid Tariff. Market Conditions will be assessed every 6 months. DisCo Grid Tariff will be amended to pass through changes based on the DisCo MYTO tariff review process with the regulator. 	<p>Customers have expressed that electricity cost volatility significantly affects their business and is a primary factor in their decision-making process for supply options. At the same time, a lock-in tariff may hurt or be in favor of economics for the DER developer and the DisCo. For example, if the Blended Tariff remains the same but the DisCo Grid Tariff increases from MYTO review, it reduces the portion of the Blended Tariff that is returned to the DER developer.</p> <p>The intent of these adjustments is to provide a transparent, structured way the Blended Tariff can and cannot be modified, to protect the interest of all three parties.</p>





ITEM	CLAUSES IN THE TEMPLATE	RATIONALE AND FURTHER CONSIDERATIONS
Under-performance	<ul style="list-style-type: none"> If DER developer fails to meet the minimum supply during its priority hours, the developer shall pay the customer liquidated damages based on actual performance (details are defined in the contract) If DisCo fails to meet the minimum grid availability, the DisCo will be liable to pay the DER developer the Recoverable Expenditure, which equals the grid electricity supply discrepancy multiplying either DisCo Premium Fee or Extraordinary Backup Tariff (detailed clauses are included in different versions of the template for reference) <ul style="list-style-type: none"> The Extraordinary Backup Tariff is the tariff the DER developer will charge per kWh, reflecting the added diesel cost running backup generation in absence of grid supply. This is suitable for projects where the developer is investing in and managing (new) backup generation assets, and anticipating significant diesel consumption.xxvii The Premium Fee is introduced to incentivize DisCo to improve service for the customer and support them to recoup grid upgrade costs. In case of underperformance, those incentives would be deducted accordingly. This is suitable for projects where the customer is maintaining their existing genset.xxviii The Recoverable Expenditure will be subtracted from the total amount the DER developer owes the DisCo for electricity supplied from the grid. The DER developer will provide backup when the grid fails, to ensure high overall reliability to the customer. 	<p>The DER developer is sizing the DER system based on the assumed DER Priority Hours where it will need to supply the C&I customer, as well as the amount of time it will need to back up the grid supply. If the DER developer is required to back up the grid supply for more time than initially expected, that likely requires the DER developer to run expensive diesel generators. This places an undue financial burden on the DER developer. The calculated Recoverable Expenditure offers the parties a way to easily and systematically resolve this when it's a once-in-a-while occurrence (The amount also shouldn't be significant as the grid availability standard is pre-aligned with DisCo and we asked the DisCo to come up with "minimum" hours they feel confident to guarantee supply and have incorporated it into system design).</p> <p>These clauses are designed to protect both the DisCo and the DER developer. If the DisCo is not meeting its Grid Availability Standard, it owes the DER developer for excess electricity the DER developer produces. If this persists, the DisCo could owe the DER developer more than the DER developer owes the DisCo for electricity it supplies, which will then lead to termination of the DisCo's supply obligation to the customer (so the contract becomes a bilateral agreement between the developer and the customer). This protects the DER developer from being owed money by the DisCo. This also protects the DisCo from racking up debt to the DER developer without a clear termination point.</p>

ITEM	CLAUSES IN THE TEMPLATE	RATIONALE AND FURTHER CONSIDERATIONS
Termination	<ul style="list-style-type: none"> The customer, DER developer and DisCo have the right to terminate the agreement after following the dispute resolution steps outlined in the contract and the issue persists. <ul style="list-style-type: none"> If DisCo fails to meet the minimum Grid Availability Standard for a consistent period, the DisCo's supply obligations would be terminated, and the DER developer and customer can enter into a bilateral agreement. If the DER developer breaches, the developer will uninstall the system and restore land, rooftop to good condition, at its own cost. If the customer defaults, the customer may purchase the asset at Fair Value, or pay the DER developer a termination fee which is calculated based on remaining book value of assets. 	<p>This is a new business model arrangement, and these clauses give all three parties a way to exit in extreme circumstances. For example, DER developers may be wary of the DisCo's ability to provide reliable grid supply. The DER developer is making a large capital investment in the project and does not want that investment to be lost if the DisCo ultimately cannot perform. To mitigate this perceived risk, the tripartite agreement allows the DER developer and C&I customer to enter a bilateral arrangement in the event that the DisCo consistently cannot meet the grid availability standard and other options to revise it have been exhausted.</p>



5.2 PRELIMINARY CONTRACTUAL NEGOTIATION

KEY TAKEAWAYS

- Understanding the business model is a prerequisite for contractual negotiation, and it is essential to clearly lay out the value proposition to DisCos and customers, highlighting benefits that matter to them the most, supported by technical and economic scenario analysis.
- This innovative model requires customers, the developer and DisCos to step outside their comfort zone, and keep an open mind. To have a fair contract and achieve win-win-win, they need to understand each other perspectives and sometime balance their interests.

Over the course of Task 5, RMI and Daystar had multiple working sessions and worked closely to present key contract terms and design rationale to DisCos and customers. In preliminary contractual negotiation, a focus is to explain the business model in great detail, making sure DisCo and customers clearly understand the value propositions, and what outcomes and responsibilities they could expect. We incorporated their overarching feedback into the tripartite agreement templates, and their specific requested modifications into detailed contract terms, as well as the technical

design (Task 2), economic analysis (Task 3) of the proposed project.

This section summarizes key feedback from DisCos and customers regarding the tripartite agreement, along with our observations and suggestions on how to approach the discussions. These are the sticking points in contract discussions, and this summary will hopefully help Daystar better anticipate contract negotiation and facilitate the finalization of proposal and contracts.





5.2.1 SUMMARY OF DISCO FEEDBACK

While DisCos have some experience working with DER developers and entering into long-term contracts with them, one point to emphasize to DisCo is that in this business model, Daystar and DisCos are collaborating partners serving the customer together, who both want the project to work and sustain thus should both come in with good faith. Below are major discussion topics that came up during contract negotiation with DisCos:

DISCO UNDERPERFORMANCE PENALTY:

Even though we expect this to happen only rarely provided that the system is properly designed accounting for minimum grid availability, DisCos should be held accountable if they fail to meet their obligations (similarly for Daystar). DisCO either lack existing mechanism, or the current practice doesn't suit our proposed business model. IE for example, does provide liquidated damage in existing bilateral agreements with customers but the amount is very minimum and won't be fair for Daystar. AEDC expects that any liquidated damage should not have an impact on their current revenue from the customers. (As precedent, the same rational is applied when AEDC sets the distribution usage fee for interconnected mini-grids.) Based on the feedback from the Discos we came up with two methods to calculate the underperformance penalty ("Recoverable Expenditure" in the contract):

1. Linking it to the Disco Premium Fee—this is most straightforward in calculation and financial settlement, and since it won't affect DisCo's "business-as-usual" revenue, we found that it's easier for DisCo to accept the term.
2. Linking it to additional diesel (or gas) fuel costs in providing backup for the grid. This would more accurately reflects Daystar's added costs, but it will require more efforts in tracking and verifying fuel costs.

The underperformance penalty amount will be deducted from DisCo bills to Daystar, as it's very difficult to have DisCo make out payment to the developer. For each transaction, Daystar need to do a sense check on DisCo's expected

revenue and total debts to make sure there is enough monthly revenue to cover monthly debts in extreme situation.

GRID UPGRADE REPAYMENT PERIOD:

This is a term which Daystar and DisCos need to balance each other's interests and align on a case-by-case basis. In general, Daystar would like to recoup the investment on grid upgrades as soon as possible, while DisCos want to spread the cost across project lifespan. The repayment period will affect the monthly repayment amount, and it's also worth considering how the amount compared to DisCo's expected monthly revenue—whether Daystar can deduct the amount from DisCo invoices (also see related sensitive analysis discussed in Task 3 report). In addition, there are clear terms in the contract stating that if DisCos default before the full grid upgrade investment is paid off, DisCos will still be liable for the remaining balance.

BANK GUARANTEE REQUIREMENT:

DisCos all initially requested payment security from Daystar which we later persuaded them to waive, noting that it's difficult and not fair for Daystar (or other developers) to set aside the fund for multiple customers at the same time. Instead, we design terms to allow the DisCo to directly bill the customers if the developer misses consecutive payments and DisCo can request documents from Daystar to verify their financial health (e.g., Daystar applied for and was granted pre-qualified supplier status with AEDC).

Here are some additional considerations for future transactions. Developers are encouraged to conduct further Know-Your-Customers to select a viable customer, making sure the customer is in good financial standing and has a good credit history. DisCos can pre-select partnering developers through a Request for Qualifications (RFQ) process (like Daystar did with AEDC), where they can vet the financial credibility and capabilities of developers along with other evaluation criteria.



■ PAYMENT TERMS AND TIMELINE:

This will likely vary by DisCos. For example, IE requires a quicker turnaround for payment compared to AEDC. Thus Daystar aligned with DisCos and customers to properly sequence respective invoice and payment timeline. Even though the requirements for bank guarantee has been waived in the tripartite template, Daystar may consider requiring payment security from less credible (or financially strong) customers, to make sure timely payment to pass along to DisCos while protecting itself.





5.2.2 SUMMARY OF CUSTOMER FEEDBACK

The main challenge in preliminary contractual negotiation with customers is that customers are not familiar and often not comfortable with a long-term power supply agreement. For them to make the leap, they need clear value add (e.g., significant expected cost savings) while building trust towards the developer and DisCos. Especially for the DisCos, customers usually are concerned if the DisCos can meet their obligation as agreed with the developer. It's important to highlight to customers the benefits of the business model (such as high reliability with DER and grid as the developer will provide the funding for network improvement, no upfront cost, less dependence on diesel, higher power quality, etc.) that appeal to certain customer the most, and explain clearly how the electricity demand will be met, the expected cost and potential tariff review and adjustment processes, and how their interests are being protected. Customers raised the following discussion points when we presented the contract:

PRICING:

Customers are naturally sensitive to costs. While it is sometimes possible that Daystar can offer lower tariff by adjusting the system design and other means, customers need to understand that the adjustment may reduce reliability and likely result in more diesel/gas consumption. The Blended Tariff is also subject to review every six months to calibrate market conditions and when new DisCo tariffs come in effect, so the customers are not locked in with current rate. It might be worth noting to customers that the tariff adjustment can go both ways (higher or lower), and market conditions and DisCo tariff changes will affect the customer even if they don't participate in the project.

UNDERSTANDING THE FINANCIAL EXPOSURE:

Even though the business model requires no upfront capital investment from the customers, some customers are still interested in understanding the financial exposure, in case they would be liable (e.g., if they default and have to pay termination fee, which is calculated with remaining book value of assets). If requested and for increased transparency, Daystar could include asset costs and depreciation schedule in Schedule 4—Details of Fixed Infrastructure for Generation Assets in the contract (see the draft contract for The Wood Factory as an example).

DETERMINATION OF MINIMUM CONSUMPTION:

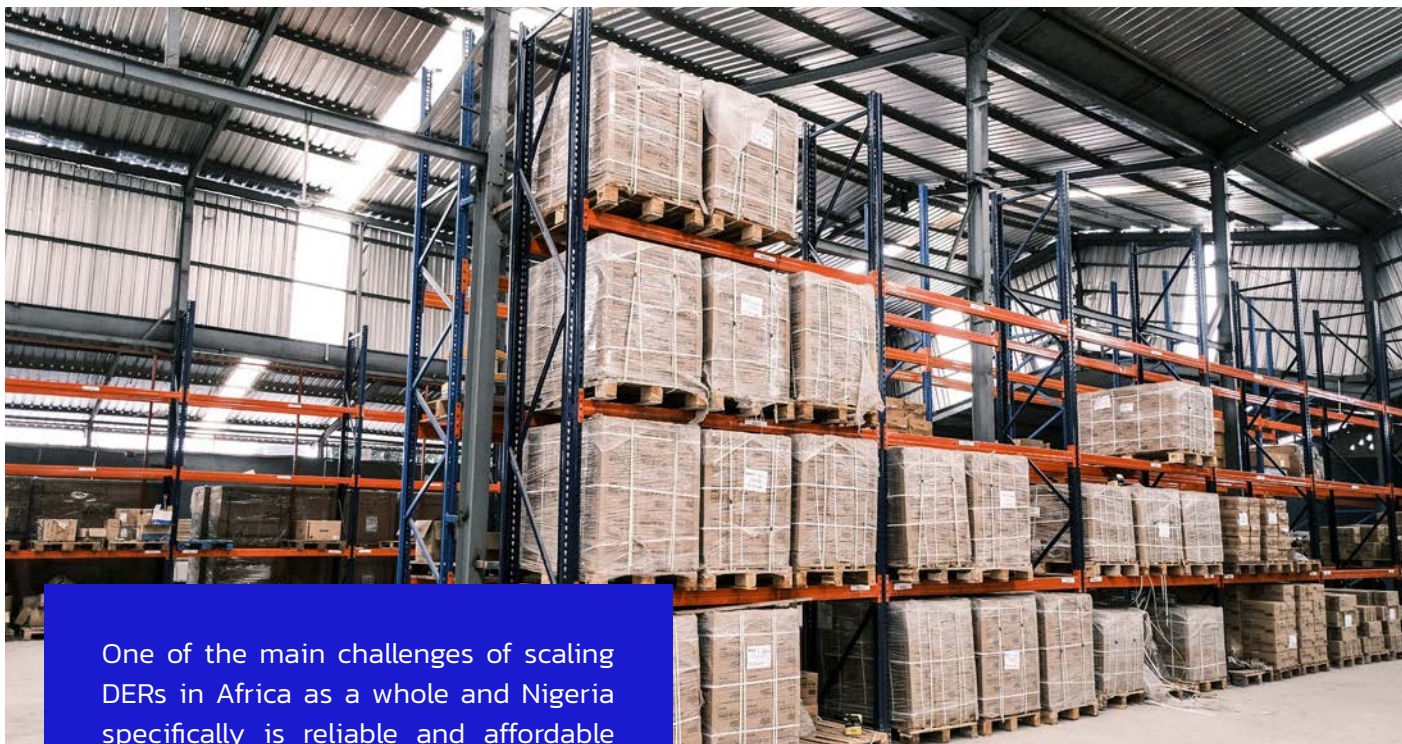
Customer's actual consumption will have significant impact on project economics (also see sensitive analysis on materialized loads discussed in Section 3). Many customers don't have a good grasp of their six-month total demand, especially without properly metered load data. Even if we logged most sites for one month, seasonal fluctuations are not captured. To reassure customers, the minimum consumption is not set and stone, and can be revisited every six months together with tariff review.

INTEGRATING EXISTING DIESEL BACKUP GENERATOR:

Most customers we engaged already own backup generator themselves and some asked if they can continue using the existing generator instead of having Daystar invest in new ones. This is possible, and in this case, it's recommended that Daystar can manage the DER system and backup generator as a whole to optimize dispatch, and the customer will be responsible to procure fuel and perform maintenance. Some terms in the contract will need to be adjusted accordingly (see "with Diesel" and "without Diesel" versions).

06

**U.S. SOURCES
OF SUPPLY
IDENTIFICATION**



One of the main challenges of scaling DERs in Africa as a whole and Nigeria specifically is reliable and affordable access to world-class equipment and services for developing and operating DER projects. There is an opportunity to increase the market size and optimize the supply of US DER products and services to Nigeria, diversifying options for developers, improving the quality of projects implemented, while also expanding US-Nigeria trade.

RMI identified U.S. companies^{xxix} that already supply or are interested in supplying renewable energy products and services for C&I DER projects in Nigeria. The companies provide DER products and services through a local Nigeria office, partner distributors, and/or through direct sales and shipment to a Nigerian port.^{xxx}

This section includes a summary of the findings on US-Nigeria DER supply chain opportunities and challenges from interviewing US

supplier representatives, contact information of identified companies as well as a description of some of the products and services the companies provide. Daystar can use this report to explore opportunities for diversifying their DER supply chain while USTDA will gain a clear understanding of the challenges and opportunities of improving US supplier engagement in the C&I DER sector in Nigeria.

Nigeria is estimated to have about 22GW of operational generators while a total of 39 African countries have a combined 100GW of operational generators^{xxxi}. U.S. suppliers have the opportunity to participate in the growing clean energy market across Nigeria and Africa. They can provide the equipment and services DER developers require to scale the utility-enabled DER business model and transition the electricity supply to affordable solar battery systems, especially given the rising cost of diesel.

For this USTDA funded project, RMI designed DER

^{xxix} Comprising only companies originating from or headquartered in US or companies with a US-based subsidiary.

^{xxx} DER developers are responsible for clearing and collecting products purchased this way at the port terminal.



systems for 20 C&I sites^{xxxii} and estimates a \$30 million equipment supply opportunity for some

of the components from US-based suppliers as highlighted in Table 40 below:

Table 40: Equipment supply opportunity for the 20 C&I sites

COMPONENT	TOTAL DEMAND FOR 20 C&I SITES	ESTIMATED DOLLAR VALUE (\$ MILLION)	COST ASSUMPTION PER UNIT
PV Modules	27.2 MW	[REDACTED]	[REDACTED]
PV Inverters	21.7 MW	[REDACTED]	[REDACTED]
Batteries	20.2 MWh	[REDACTED]	[REDACTED]
Diesel Generators	14 MW	[REDACTED]	[REDACTED]

6.1 APPROACH TO IDENTIFY POTENTIAL U.S. SOURCES OF SUPPLY

KEY TAKEAWAYS

- RMI identified and categorized the US sources of supply based on their level of engagement in Nigeria ranging from “no evidence of presence in Nigeria” (Level 1) to “operating a local office or having a sales representative in Nigeria” (Level 4).
- The research conducted by RMI was timebound and subject to accuracy of qualitative data from partners in Nigeria and is therefore not exhaustive of the entire DER component landscape in Nigeria.

RMI’s objective of completing “Task 6: US Source of Supply Identification” was to identify US suppliers that already provide or are interested in providing C&I-scale DER products and services in Nigeria as well as gain insight in the characteristics of the supply chain and barriers limiting scaling of the US-Nigeria DER supply chain.

RMI created the list below based on local knowledge of the DER sector by Nigeria-based team members, discussion with Nigerian DER developers and partners that support and/or procure C&I-scale

equipment and services, peer review from the Daystar procurement team and desk research of renewable energy projects under implementation in Nigeria and their listed suppliers.

The list of suppliers below is therefore not an exhaustive list of all US suppliers that can potentially supply DER equipment and services in Nigeria, but focuses on those that supply, previously supplied, or are interested in supplying in Nigeria in the near future (withing a year).

^{xxxix} Comprising only companies originating from or headquartered in US or companies with a US-based subsidiary.

^{xxx} DER developers are responsible for clearing and collecting products purchased this way at the port terminal.



Table 41: Levels used to differentiate suppliers' level of engagement in the Nigeria DER sector

ENGAGEMENT LEVEL IN NIGERIA	DESCRIPTION
1	No evidence of product or current supply chain in Nigeria
2	Evidence of product in retail stores in Nigeria
3	Evidence of direct sales or local partners in Nigeria
4	Evidence of local office or sales and marketing representative in Nigeria

Annex 6–A lists the 43 US supply companies RMI identified, divided into the four levels of DER sector engagement in Nigeria shown in Table 41. RMI collected data for assessing the suppliers against the levels in Table 41 through interviews and email correspondence with supplier representatives, desktop research on projects the companies have participated in as well as information from developers executing projects in Nigeria.

Table 42 shows the breakdown of the 29 companies across levels of engagement in the Nigerian market, with active equipment supply chains for C&I DER projects. These are companies categorized as Level

2–4 in Table 41 above. The companies sell products in Nigeria through a local office, representative or distributor or directly import products and service for customers to a port in Nigeria for their individual processing. A few of the companies provide products and services across more than one component category e.g., SMA America which sells inverters and provides distribution services on a project-to-project basis. Level 1 companies with no identified participation in the Nigerian DER market may be more relevant in the future if they develop an active interest or presence in Nigeria.

Table 42: Current Level 2– 4 suppliers for C&I-scale DER equipment and services

COMPONENT	NUMBER OF COMPANIES	LEVEL
PV Modules	5	2–4
PV Inverters	3	2–3
Batteries	4	3–4
Diesel Generators	2	4
Distribution system solutions	3	2–4
Smart Metering & Billing	1	4
Software Provider (System Design & Monitoring Solutions)	7	3–4
System Engineering, Procurement, and Construction	4	4

^{xxxxi} Benjamin Attia and Gail Anderson, "Belching in the Background: Sizing Africa's Distributed Diesel Power Landscape and Displacement Opportunity," no. April (2022).

^{xxxxii} RMI completed preliminary analysis for 22 sites, but two customers were deprioritized for further analysis due to their low interest in long-term contracts with DisCos under the proposed 10-year tripartite agreement for the C&I DER business model.

RMI engaged in call interviews and email correspondence with the U.S. suppliers identified as Level 3 or 4 (evidence of direct sales, local partners, or local office) to verify what C&I DER products and services they offer and establish their interest in supplying to projects in Nigeria. Level 3 and 4 suppliers were prioritized for engagement because they have experience in the Nigerian DER market, making them suitable partners to support Daystar in implementing over 20 utility-enabled DER projects.

As part of the interview and/or email correspondence, RMI included questions to ensure collection of key data points required by USTDA and Daystar for effective future engagement with the suppliers (see Table 43).

Table 43: Questions included in supplier interviews and/or email correspondence

KEY QUESTIONS
Contact details of the company's representative
Description of their C&I DER products and services
Breakdown of their product or service delivery turnaround times
Description of their experience in the Nigerian Market focusing on supply challenges where applicable

Annex 6–B shows the detailed interview form RMI used to engage with the suppliers as well as summary notes of some of the supplier interviews.

Table 44 is a summary of the 25 companies RMI identified as Level 3 and 4 suppliers and subsequently engaged or interviewed. These constitute suppliers of PV modules, PV inverters, batteries, diesel generators, distribution hardware like inverter controllers, smart metering, billing hardware and software as well as system design and monitoring software. DER Engineering, Procurement, and Construction (EPC) companies are also included in the table though Daystar typically executes this aspect of system development for their customers and most EPC firms in Nigeria (even those affiliated to US entities) are local direct competitors of Daystar.

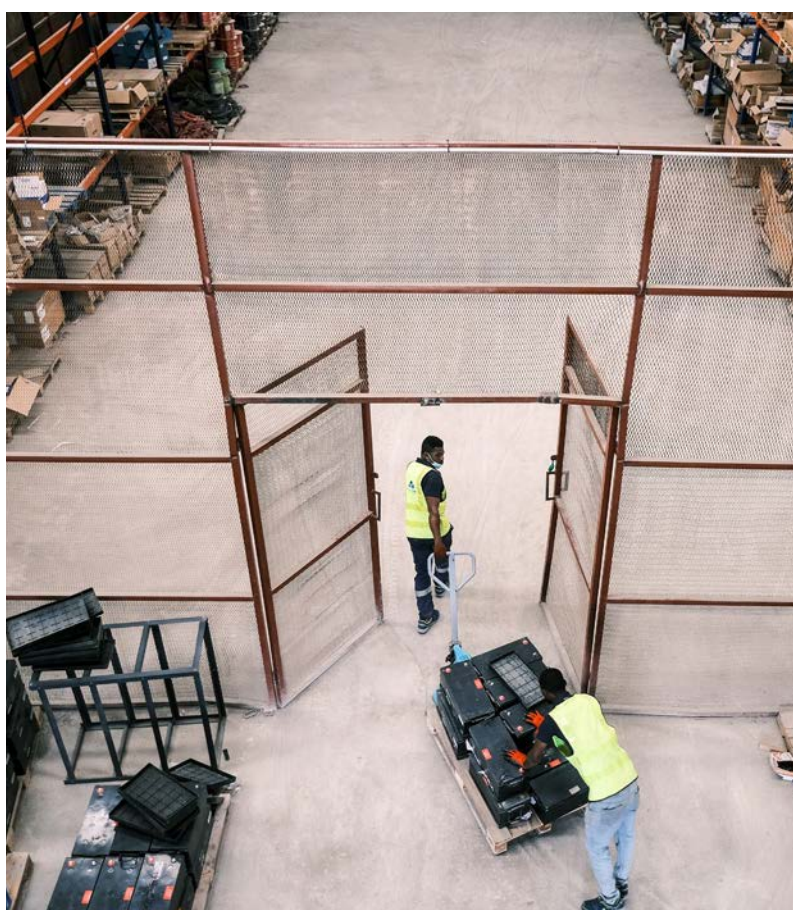




Table 44: List of Level 3 and 4 companies engaged by RMI, including status of engagement

COMPONENT	COMPANY	ENGAGEMENT LEVEL	ENGAGEMENT STATUS
PV Modules	Trina Solar	4	Interviewed
	Maxeon (SunPower)	3	Interviewed
PV Inverters	SMA America	3	Interviewed
	Solectria Yaskawa	3	Reached out
Batteries	Tesla	3	Reached out
	Trojan Battery	4	Interviewed
	Jinko Solar	4	Interviewed
	EoS Energy Storage	3	Reached out
	Simlphi	3	Interviewed
Diesel Generators	Caterpillar (Mantrac)	4	Interviewed
	Cummins (Globeleq)	4	Interviewed
Distribution system solutions	SMA America ^{xxxiii}	3	Interviewed
	General Electric	4	Interviewed
Smart Metering & Billing	Spark Meter	4	Interviewed
Software Provider – system design, monitoring solutions and maintenance	Homer Energy (UL Renewables)	3	Interviewed
	Odyssey Energy Solutions	3	Interviewed
	New Sun Road	3	Reached out
	Shyft Power Solutions	4	Reached out
	Oracle	4	Reached out
	60 Hertz	4	Interviewed
System Engineering, Procurement, and Construction	PowerGen ^{xxxiv}	4	Interviewed
	Rensource	4	Interviewed
	Renewvia	4	Interviewed
	Ashipa Electric Limited	4	Reached out
	NXT Grid B.V	4	Reached out

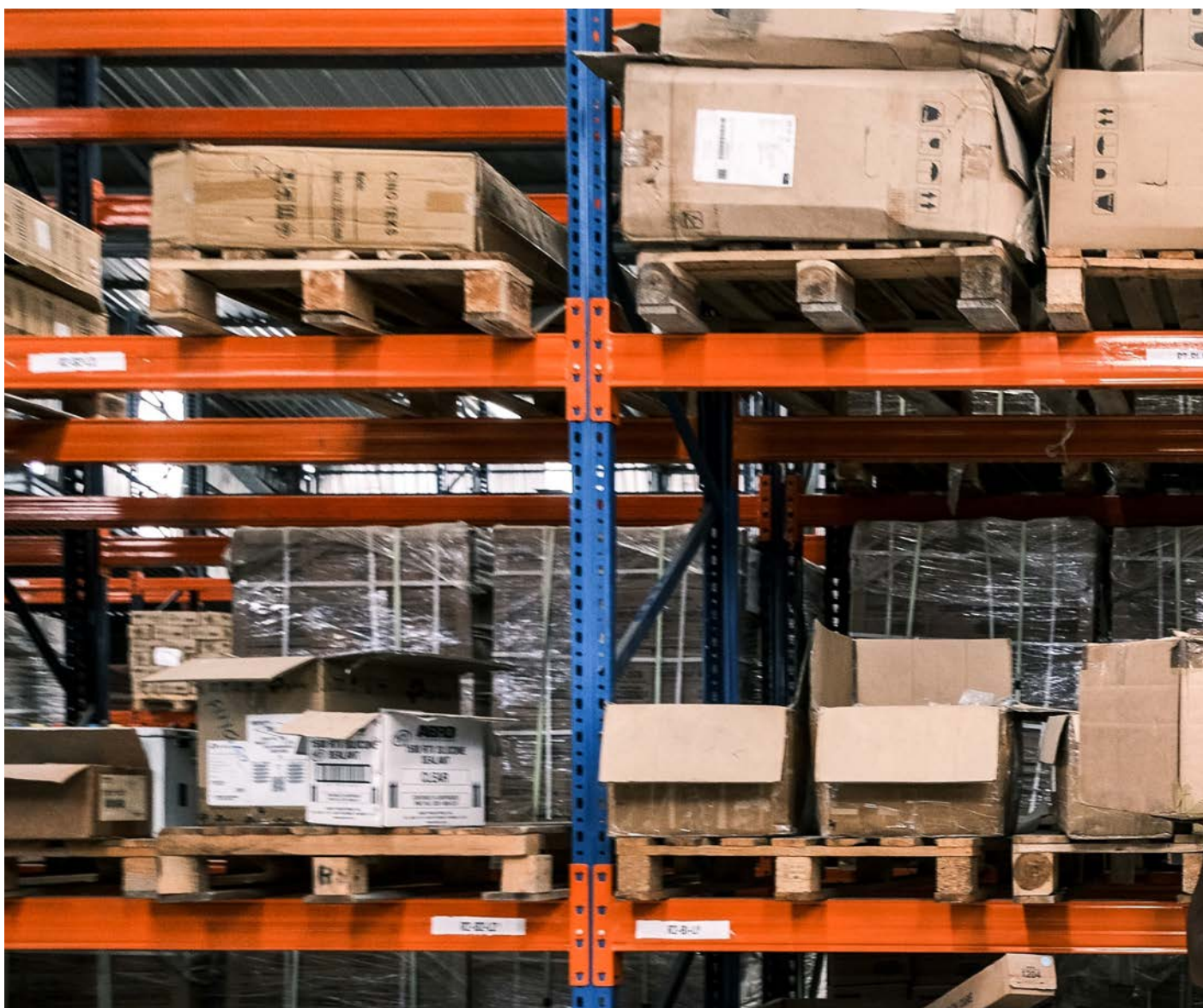
^{xxxiii} As noted in Annex 6, while SMA has U.S. manufacturing their representatives state that current supply to Nigeria uses German-manufactured products.



6.2 U.S. SUPPLIERS IDENTIFICATION INSIGHTS

KEY TAKEAWAYS

- Nigeria has untapped market potential for large-scale DER components supply that US suppliers are currently not substantially involved in.
- The ripple effects of the global supply chain shortages post Covid pandemic are still affecting supply capabilities of the few US suppliers participating in Nigeria.
- Government-level interventions such as trade agreements and fiscal incentives are necessary to achieve the required scale of DER components for widespread deployment of C&I DERs.





6.2.1 GENERAL MARKET OBSERVATIONS

THERE IS LIMITED ENGAGEMENT OF US SUPPLIERS IN SOME OF THE DER PRODUCT CATEGORIES IN NIGERIA

The Nigerian DER market mostly relies on low-cost generic brand products that are made in China for standardized equipment like PV modules. Developers describe these products as being of “average quality” i.e., neither top rated nor poor quality and are therefore functional within the financial and performance constraints that developers confront. It is estimated that approximately 50% of the market share is controlled by the oldest PV supplier in the market, Jinko, 30–35% by JA Solar, while the remainder is shared by various other PV companies. From discussions with developers in Nigeria, RMI found that they mostly use US supplier PV modules for projects with a long-term agreement between partnering companies e.g., Total has a long-term agreement with SunPower modules for its fueling stations and its solar home solutions.

Similarly, developers mostly use generic brand lead acid batteries from China, while slowly shifting to other battery chemistries like lithium ion and lead carbon. Developers are comfortable using these generic batteries because they come with warranties from the distributors that provide performance assurance for their DER projects.

However, developers prefer to use top quality recognizable brands from US and European suppliers for DER equipment which is critical to ensuring power supply reliability like inverters, power conditioning equipment and high-power generators. Developers show little sensitivity to

the high cost of this equipment compared to other low-cost versions that are available on the market because they consider that equipment to have higher quality and reliable performance.

Developers use low-cost PV and battery racking or mountings and distribution lines that are manufactured in Nigeria unless they come as part of an integrated solution e.g., battery suppliers Tesla and Eos Energy Storage provide battery racking as part of their battery solution. Eos procures battery containers along with racking from China which minimizes overall product costs. With regard to distribution lines, Nigeria has federal policies related to local content that drive local manufacturing of distribution lines and power cabling. The Federal Government of Nigeria set a high standard for the development of cables and wires through the Standard Organization of Nigeria (SON) to support utilization of the various incentives deployed by the government including manufacturers’ easy access to bank loans.^{xxxv} Developers and EPC companies prefer purchasing local cables and wires due to their affordability and quality.^{xxxvi}

US SUPPLIERS ARE MOSTLY MANUFACTURING THEIR PRODUCTS IN CHINA AND MEXICO

The companies RMI interviewed develop products in the US and organize their manufacturing around assembling close to local sources of process inputs or components, for easy access to the supply chain and lower cost of manufacturing. This has resulted in fewer manufacturing plants (if any) in the US, most manufacturing taking place in China and Mexico and a few Europe-based manufacturing plants.

^{xxxiv} PowerGen and other EPCs expressed interest primarily in owning and operating DER projects but are less interested in a strictly EPC role in Nigeria.

US SUPPLIERS FAVOR SHIPPING PRODUCTS TO NIGERIA FROM CHINA OR EUROPE MANUFACTURING PLANTS

The suppliers RMI interviewed expressed preference for shipping products to Nigeria from their Chinese and European plants, even in situations where they have manufacturing in the US. The cost of shipping from China and Europe is lower for the suppliers and subsequently the customer when shipping from these plants. This is partly due to economies of scale (in the case of shipments from China where a lot of other Nigeria-bound goods are shipped from annually) and complexity and long lead time of shipping processing between US and Nigeria.

THE CURRENT GLOBAL SUPPLY CHAIN CHALLENGES HAVE IMPACTED THE CAPACITY OF US SUPPLIERS TO SELL IN NIGERIA

Global supply chain shortages for technology components and other industrial process inputs induced by the Covid pandemic have forced DER equipment suppliers to prioritize regions and customers to supply resulting in some suppliers exiting Nigeria supply altogether for the next few years^{xxxv}. The suppliers lack a strong business case for prioritizing the Nigerian DER market with current supply chain shortages because they view Nigeria as a small scale market that requires “made to order” equipment, for example for C&I DER batteries. It is more expensive for suppliers to fulfil small bespoke orders because it hinders their capacity to stock large quantities of equipment in Nigeria, with the associated economies of scale.



^{xxxv} Stanley Opara, *Nigeria is the only producer of high-voltage cables in West Africa*, *The Guardian*, December 2018, <https://guardian.ng/business-services/nigeria-is-the-only-producer-of-high-voltage-cables-in-west-africa/>

^{xxxvi} *Ending Influx of Substandard Cables in Nigeria*, *ThisDaylive*, June 2017, <https://www.thisdaylive.com/index.php/2017/06/27/ending-influx-of-substandard-cables-in-nigeria/>

^{xxxvii} *A Tesla representative expressed that though they have previously supplied batteries to C&I projects in Nigeria in the recent past, the demand for their batteries has outpaced their supply rendering the company unable to supply to Nigeria for the next two years.*

^{xxxviii} <https://www.all-on.com/dart-program.html>



6.3 U.S. SUPPLIER CONTACT INFORMATION AND NEXT STEPS

KEY TAKEAWAYS

- The reliability of supplier contact information is subject to staff mobility as employees transition to other companies and roles.
- The list below is subject to market-driven changes as some of the companies identified by RMI at the start of the project in late 2021 have undergone bankruptcy proceedings, merged with other companies or fully dissolved. These companies are not included in the list below but represent the risk associated with early-stage component suppliers in the growing renewable energy market.

RMI engaged most of the companies identified as Level 3 and 4 suppliers to validate their interest in supplying to C&I DER projects in Nigeria and obtained positive feedback from various suppliers. We also provided the list of suppliers to the Daystar procurement team for their validation and record to reference as needed when procuring DER equipment. Table 45 is the list of US suppliers and their contact information and includes the local companies representing the US suppliers, shown in parentheses.

Moving forward, RMI recommends that USTDA further engages the US suppliers included in this research to identify and support opportunities for participating in scaling the Nigeria DER equipment supply chain. One opportunity RMI identified is the DART program (Demand Aggregation for Renewable Technology) xxxviii. Participating in this program could create the high equipment demand required to improve economies of scale for US suppliers that will make their products competitive in comparison to the low cost products available in the Nigerian DER market.

Table 45: U.S. supplier contact details for Level 3 and 4 companies that RMI engaged

COMPONENT	COMPANY	CONTACT	STATUS OF ENGAGEMENT
PV Modules	Maxeon (SunPower)	Antoine Lefresne Sales Manager Africa & Middle-East +33-66-508-4549 antoine.lefresne@maxeon.com	Interviewed
	Trina Solar	Sam Ogunniyi Sales Advisor Africa & Middle-East +234-803-200-9022 ogunniyi.sam@trinasolar.com	Interviewed
PV Inverters	SMA America	Eduardo Rocha Regional Sales Manager (Nigeria & Ghana) +49-151-1486-9494 eduardo.rocha@sma.de	Interviewed
	Solectria Yaskawa	John Lavelle Sales Manager +1-510-385-8315 John.lavelle@solectria.com	Email correspondence



COMPONENT	COMPANY	CONTACT	STATUS OF ENGAGEMENT
Batteries	Tesla	David Arnaud Senior Account Manager, Energy – Europe and Africa Manager EMEA C&I Sales +33 (0) 669 104 628 darnaud@tesla.com	Email correspondence
	Trojan Battery	Gerrit Barnard Sales Manager Africa +2-783-504-8528 gbarnard@trojanbattery.com	Interviewed
	Simlphi	Rick Doub Senior Manager, Global Business Development +1-805-640-6700 rickd@simliphipower.com	Previously interviewed
	Jinko	Charles Mezu CEO, Palette Eng (Jinko distributor) +234 8033731860 sales@paletteng.com	Interviewed
	Eos Energy Storage LLC	Andrew Hughes Manager of Sales & Business Development +1-347-534-6789 ahughes@eose.com	Previously interviewed
Diesel Generators	Caterpillar (Mantrac)	Adetutu Moronke Mesele Sales Manager amesele@mantracnigeria.com	Strategy Manager previously interviewed
	Cummins (Globeleq)	Longe Alonge Business Development Director +234-813-931-9994 longe.alonge@globeleq.com	Previously interviewed
Distribution system solutions	SMA America	Provided above	Interviewed
	General Electric	Stephen Imomoh Director GE Renewables West and Central Africa +234-906-287-5817 stephen.imomoh@ge.com	Previously interviewed
Smart Metering Solution	Spark Meter	Morayo Osiyemi Director of Utility Business development +234-909-022-2486 morayo.osiyemi@sparkmeter.io	Previously interviewed



COMPONENT	COMPANY	CONTACT	STATUS OF ENGAGEMENT
Software Provider/ System Design, Monitoring and maintenance	New Sun Road	Michael Goldbach CPO mgoldbach@newsunroad.com	Did Not Respond
	Homer Energy (UL Renewables)	Dr. Chakradhar Byreddy Business Development Manager Sub-Saharan Africa +27-76-297-0138 chakradhar.byreddy@ul.com	Previously interviewed
	Shyft Power Solution	Contact us - Website	Did Not Respond
	Odyssey Energy Solutions	Emily McAteer CEO +1-978-505-9423 emily@odysseyenergysolutions.com James Wang Project Delivery Manager james@odysseyenergysolutions.com	Interviewed
	Oracle	Temitope Onaolapo Manager +234-1-448-010 temitope.onaolapo@oracle.com	Did Not Respond
	60 Hertz	Piper Wilder CEO +1970-355-9221 piper.wilder@60hertzenergy.com	Previously interviewed
System Engineering, Procurement and Construction	Powergen Renewable Energy	Aaron Cheng CEO +234-906-5157-471 +254-701-484-159 acheng@powergen-re.com	Previously Interviewed
	Rensource Energy	Ademola Adesina Non-Executive Director ademola.adesina@rensource.energy	Previously Interviewed
	Renewvia Energy	Chris Ebiware Country Manager +234-803-9253-885 cebiwaree@renewvia	Previously Interviewed
	NXT Grid B.V	Bert Dequae Lead (3)-625-374-049 bert@nxtgrid.co	Did not Respond
	Ashipa Electric Limited	Olugbenga Ajajal CEO (234)-803-0463-676 oajala@ashipaelectric.com	Did not Respond

07

**PRELIMINARY
ENVIRONMENTAL
AND SOCIAL
IMPACT
ASSESSMENT**



KEY TAKEAWAYS

- RMI engaged AquaEarth Consulting Limited to conduct preliminary environmental and social impact assessments (PESIAs) for 18 pipeline sites. These PESIAs identified the major environmental and social risks related to implementing the projects, proposed mitigation measures for those risks, and developed a plan to close the identified gaps. No significant risks that would pose an immediate threat to the project success were identified.
- Conducting the PESIA ensures regulatory compliance for projects that require NERC license or permit (e.g., implementing under the Minigrid Regulation). We recommend integrating the PESIA with project team site assessment earlier on to streamline customer engagement and site visit plans.

To ensure that the implementing the proposed projects would not have any unintended environmental or social impacts, RMI and Daystar engaged AquaEarth Consulting Limited (AquaEarth), an environmental and sustainable development consulting firm based in Nigeria to conduct preliminary environmental and social impact assessments (PESIA) for pipeline sites. The main objectives of the PESIAs are:

- To identify and categorize environmental and social (E&S) risks associated with the utility-enabled C&I projects if implemented.
- To propose mitigation measures for the identified E&S risks and gaps and recommend further assessment as necessary.
- To develop an Environmental and Social Action (Management) Plan to manage the identified E&S risks and gaps.
- For projects that require NERC license or permit to construct (e.g., implementing under the Minigrid Regulation), conducting the PESIA ensures regulatory compliance.

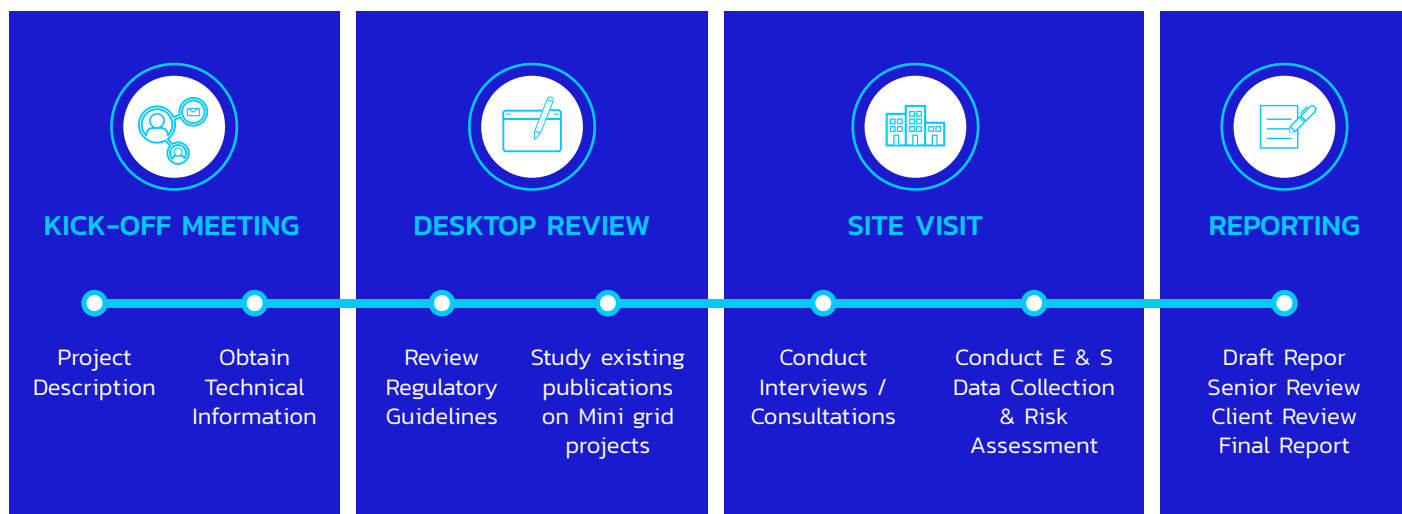
RMI and Daystar held a virtual kickoff meeting with AquaEarth, and we confirmed pipeline sites, Daystar engaged customers and coordinated site visits for AquaEarth to go on 18 C&I customer facilities to carry out PESIA.

Table 46 List of sites where PESIA is conducted

NO	NAME OF CUSTOMER	DISCO
1	[Customer 1]	AEDC
2	[Customer 2]	AEDC
3	[Customer 3]	AEDC
4	[Customer 4]	AEDC
5	[Customer 5]	AEDC
6	[Customer 6]	AEDC
7	[Customer 7]	AEDC
8	[Customer 8]	AEDC
9	[Customer 9]	AEDC
10	[Customer 13]	AEDC
11	[Customer 14]	IE
12	[Customer 15]	IE
13	[Customer 16]	IE
14	[Customer 17]	IE
15	[Customer 18]	IE
16	[Customer 19]	EKEDC
17	[Customer 20]	EKEDC
18	[Customer 21]	EKEDC

AquaEarth team prepared PESIA reports for each of the 18 pipeline sites, which discuss project overview (Chapter 1 in each PESIA report), applicable regulatory framework (Chapter 2), risk and compliance gap assessment (Chapter 3), environmental and social action (management) plan (Chapter 4) and scoping further E&S deliverables (Chapter 5).

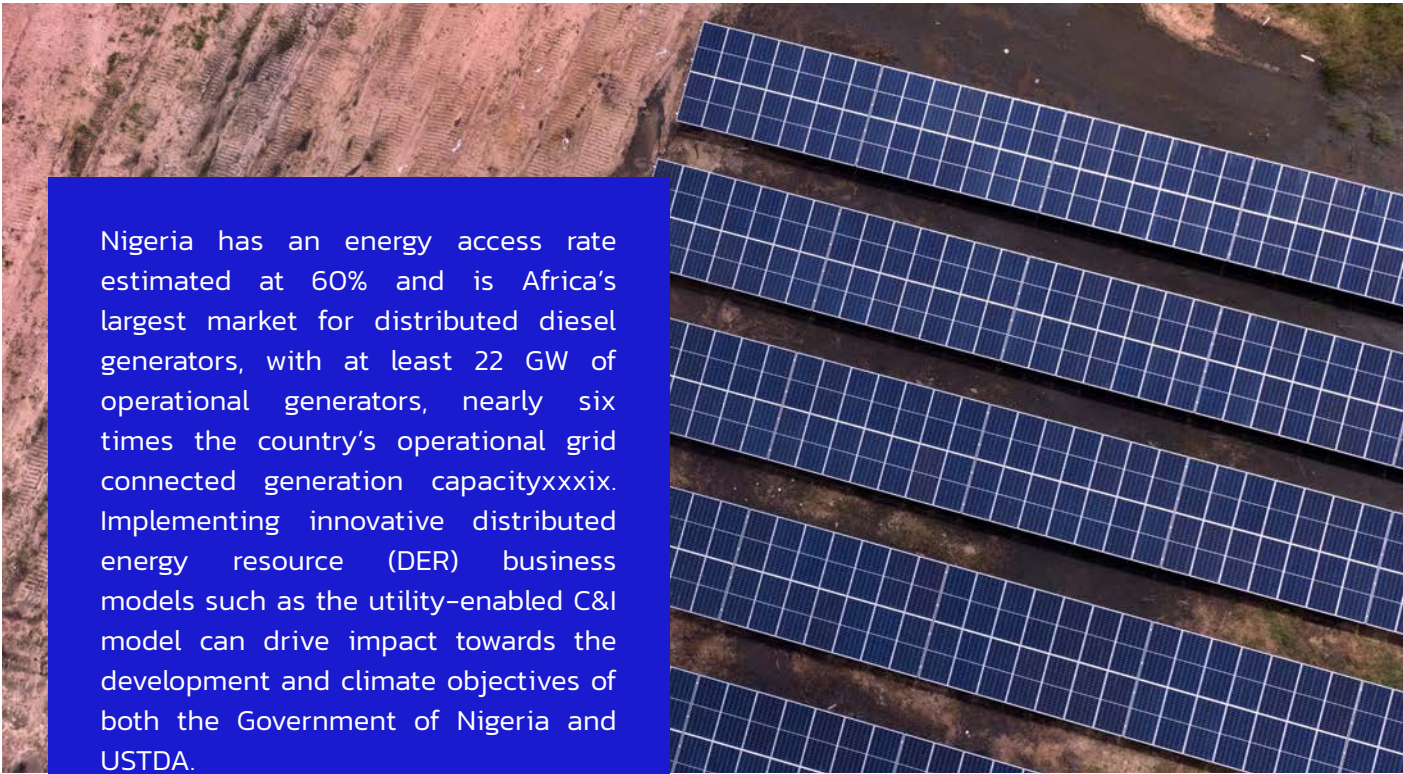
Figure 33 PESIA methodology by AquaEarth





08

**CLIMATE
CHANGE AND
DEVELOPMENT
IMPACT
ASSESSMENT**



Nigeria has an energy access rate estimated at 60% and is Africa's largest market for distributed diesel generators, with at least 22 GW of operational generators, nearly six times the country's operational grid connected generation capacity^{xxxix}. Implementing innovative distributed energy resource (DER) business models such as the utility-enabled C&I model can drive impact towards the development and climate objectives of both the Government of Nigeria and USTDA.

Direct development impacts include supporting and stimulating economic development by increasing renewable energy generation capacity in Nigeria and expanding access to reliable and affordable electricity by increasing generation capacity and improving distribution networks, bringing Nigeria close to achieving the country's goal of increasing electricity access to 90% by 2030^{xl}. Successful implementation of innovative business models at scale will help the Nigerian government achieve its solar PV capacity target of 13 GW by 2030^{xli}. Furthermore, having reliable power supply will enable many businesses to operate at full capacity, contributing to economic growth. The increased adoption of more efficient

and resilient renewable electricity sources will also reduce the cost of electricity for Nigerian businesses given the increasing cost of diesel generation.

Climate impacts include reducing greenhouse gas (GHG) emissions from electricity generation which supports Nigeria's Nationally Determined Contribution (NDC) target of reducing GHG emissions by 20% unconditionally or 45% conditional on receiving support from developed nations by 2030^{xlii}. In addition, Nigeria's population and economy are expected to grow rapidly over the next few decades, increasing energy consumption. Scaling innovative DER business models will support provision of reliable electricity to businesses and communities while controlling growth in GHG emissions.

^{xxxix} Benjamin Attia and Gail Anderson, "Belching in the Background: Sizing Africa's Distributed Diesel Power Landscape and Displacement Opportunity," no. April (2022).

^{xl} Rural Electrification Agency, "Rural Electrification Goal," accessed September 22, 2023, <https://rea.gov.ng/theagency/rural-electrification-goal/>.

^{xli} IRENA, Renewable Energy Roadmap 2030, 2016.

^{xlii} Climate Transparency, "Climate Transparency Report | 2020 Nigeria 2," no. May (2020): 1–20, <https://www.climate-transparency.org/wp-content/uploads/2021/01/Nigeria-CT-2020.pdf>.



Daystar and RMI seek to develop and de-risk a pipeline of 20 projects to pursue utility-enabled C&I DER business model. Our de-risking efforts include estimating the emission reduction potential and development impact of deploying the designed DERs at each site. This section provides

a summary of the emission reduction potential for the customers and scaling the business model across more sites in Nigeria. It also highlights the impact of the projects on the overall emission reduction goals of Nigeria and the United States as a development partner.

8.1 APPROACH FOR CLIMATE AND DEVELOPMENT IMPACT ASSESSMENT

KEY TAKEAWAYS

- RMI categorized the climate and development impact of implementing the C&I DER business model into 1) reduction in GHG emissions, 2) increase in renewable energy generation capacity, and 3) energy cost savings for the customers.
- The estimated climate and development impacts is subject to the data assumptions applied and the accuracy of the limited data sources.

RMI completed technical and economic analysis for 22 sites in Lagos (both EKEDC and IE territories) and Abuja (AEDC territory). Two of these sites showed low early-stage viability, as the customers have ongoing power purchase agreements and low interest in signing long-term contracts with DisCos. Hence, we prioritized 20 sites for further evaluation. We used the analysis results to estimate the climate and development impact of the C&I DER business model against three main metrics: 1) reduction in GHG emissions, 2) increase in renewable energy generation capacity, and 3) energy cost savings for the customers.

the total solar PV capacity sized by HOMER (also see Section 2) across the 20 sites for comparison against Nigeria's renewable energy growth goals.



ENERGY COST SAVINGS:

we used the DER sizing from HOMER to estimate the energy costs of the customer with the DER installed compared to their business as usual (BAU) where they currently use unreliable grid power backed-up with diesel or gas generation, resulting in cost saving estimates for each site.

RMI estimated each metric as follows:



RENEWABLE ENERGY GENERATION CAPACITY:

we completed technical modelling for each site by designing a suitable DER system in HOMER software that can reliably supply power alongside the grid, based on the DisCo's agreed grid reliability. The DER for each site is comprised of solar PV, a lithium-ion battery, and a diesel or gas generator back-up generator. We summed up



REDUCTION IN GHGS:

we used the detailed HOMER results showing energy consumption split between the grid and DER components to compute the annual energy consumption from the grid and generator. We also used the customer's reported grid and self-generation consumption to estimate the BAU

energy consumption and compared the two scenarios to estimate the emission reduction from the DER business model. We calculated the emission reduction potential by multiplying the energy consumption from each power source by the emission factor of the power source. Table 47 below is a summary of the emission factors applied. The Task 8 closeout package includes the emissions calculation excel model.



Table 47: Emission Factors by power source

POWER SOURCE	EMISSION FACTOR (G CO ₂) / KWH	DATA SOURCE
Grid	402	Climate Transparency ^{xliii}
Diesel generator (<60KW)	1580	Center for Global Development ^{xliv}
Diesel generator (>60KW, <300KW)	883	
Diesel generator (>300KW)	699	
Natural Gas	553	

RMI estimated the scaling potential for the business model using C&I customer data from the DisCos that includes the number and average power demand of C&I customers in each region. We also used Daystar’s current portfolio and operation size to estimate their scaling capacity for the C&I business model beyond the 20 sites evaluated in this project. We combined this data with the metrics above to estimate the climate and development impact of implementing the 20 sites and scaling across Nigeria.

For Daystar, we estimate a conservative scaling scenario of 36 new DER customer sites per year with their current operation size of 183 staff and an optimistic scenario of 72 customers per year assuming they doubled the operation size. From the data shared by the DisCos, we estimate that across the 11 DisCo service territories there are approximately 170,000 C&I customers^{xlv} who may be appropriate candidates for DER solutions through the utility-enabled C&I business model.



8.2 ANALYSIS RESULTS

KEY TAKEAWAYS

- The C&I DER projects provide significant climate and development impacts contingent on implementation and operation of the business model as designed.
- RMI assumed conservative scaling scenarios to reflect the typical challenges of driving wide-spread adoption of such novel business model.

8.2.1 DEVELOPMENT IMPACTS

RMI estimated that the project will improve power reliability for the 20 C&I customers we evaluated, equating to 27MW of installed solar PV capacity (sized by HOMER). Under the conservative scenario where Daystar installs DERs for 36 new customers annually with a median estimated peak demand of 250kW^{xlvi} and median installed solar PV capacity of 480KW, Daystar will develop about 17MW annually. The more optimistic scenario of doubling operations capacity and installing 72 DERs annually equates to over 34MW of solar PV capacity installed per year. Nationally, the 170,000 potential DER customers represent a solar PV demand of about 3,400MW^{xlvi}.

Table 48 Estimated renewable energy generation capacity

		NO. OF CUSTOMERS	ESTIMATED MEDIAN SOLAR CAPACITY PER SITE	TOTAL SOLAR CAPACITY
Daystar-led Implementation	De-risked projects	20	n/a	27 MW
	Conservative Scaling Scenario	36 per year	480 KW	17 MW per year
	Optimistic Scaling Scenario	72 per year	480 KW	34 MW per year
Market Overall		170,000	20 KW	3,400 MW

The economic modelling RMI completed showed an average of 26% energy cost savings for the customers and total energy cost savings for 17 of the 20 customers^{xlviii}. This would total \$76 million

over the 10-year DER project period. Dividing the total savings for the 17 customers by their total solar PV capacity equates to a project savings rate of \$2,900 per kW of solar PV installed. Assuming

^{xliii} Climate Transparency, <https://www.climate-transparency.org/wp-content/uploads/2021/01/Nigeria-CT-2020.pdf>.

^{xliv} Center for Global Development, "How Can Nigeria Cut CO2 Emissions by 63%," 2014, 1–8.

^{xlv} Task 3 report includes a detailed description for estimating the C&I customer scaling potential for Nigeria.

^{xlvi} The median peak demand for the 20 sites RMI evaluated is 250KW and median solar PV capacity from the HOMER models for these sites is 480KW.



similar savings are achievable when scaling across the 170,000 C&I sites under current market conditions, the total energy cost savings for the customers would be close to \$10 billion over 10

years of DER operation. The customers can redirect these savings into growing their businesses and boosting economic growth in Nigeria.

8.2.2 CLIMATE IMPACTS

RMI estimates the total emission reduction that the 20 customers can achieve from implementing the DERs at 25,000 tons of carbon dioxide (CO₂) annually, which is equivalent to 56% emission reduction from the customers' current BAU operations. Table 49 below shows a summary of the emissions and emission reduction for each site.

Table 49: Emissions and emission reduction

CUSTOMER	EMISSIONS (TONS OF CO ₂)				EMISSION REDUCTION (TON OF CO ₂)	TOTAL EMISSION REDUCTION
	BAU		DER			
	GRID	GENERATOR	GRID	GENERATOR		
[Customer 1]	–	715	71	42	601	76%
[Customer 2]	37	243	42	6	231	81%
[Customer 3]	107	477	111	8	465	79%
[Customer 4]	68	150	89	10	120	50%
[Customer 5]	14	112	8	1	117	97%
[Customer 6]	141	411	120	91	341	64%
[Customer 7]	119	1,386	457	355	694	38%
[Customer 8]	14	47	6	2	53	99%
[Customer 9]	421	9,714	3,632	253	6,249	47%
[Customer 10]	879	4,584	2,134	108	3,221	48%
[Customer 11]	27	474	65	1	436	81%
[Customer 13]	2,528	4,250	3,495	236	3,046	39%
[Customer 14]	149	111	91	6	162	80%
[Customer 15]	89	269	88	5	265	74%
[Customer 16]	–	14,750	6,803	477	7,470	35%
[Customer 17]	24	79	21	14	68	68%
[Customer 18]	133	437	252	22	296	43%
[Customer 19]	111	1,741	600	17	1,235	53%
[Customer 20]	87	265	67	5	281	85%

^{xlvii} We assume that the power demand of customers requiring DERs will reduce as customers with high consumptions are more likely to be among the early adopters, then there will be growing DER demand from smaller C&I customers. Therefore we used 20 kW as the average installed PV capacity for the national scaling scenario.

^{xlviii} Three of the customers evaluated showed increase in energy costs with the DER installed. This is due to these customers currently have a high grid energy consumption and/or low nighttime energy consumption.

CUSTOMER	EMISSIONS (TONS OF CO ₂)				EMISSION REDUCTION (TON OF CO ₂)	TOTAL EMISSION REDUCTION
	BAU		DER			
	GRID	GENERATOR	GRID	GENERATOR		
[Customer 21]	42	93	57	7	71	48%
Total	4,990	40,309	18,211	1,666	25,421	

The sites have an average emission reduction of 1,270 tons of CO₂. Using the average estimate and assumption that Daystar can install 36 DERs annually, they would unlock about 45,000 tons of CO₂ emission reduction and 91,000 tons for the more optimistic scenario of installing 72 DERs annually.

From the 20 customer sites we evaluated, the three lowest power demand sites have an average

solar PV design of 100KW and an average annual CO₂ emission reduction of 80 tons. Assuming the emission reduction potential is proportional to the site's power demand, scaling to 170,000 customers with average PV capacity of 20kW^{xlix} would result in about 2.7 million tons of CO₂ emission reduction annually. This is equivalent to 2.5% of Nigeria's 110 million tons of energy related CO₂ emissions in 2020^l.



^{xlix} We assume that a site with 20kW PV capacity has a fifth of the emission reduction potential of a site with 100KW PV capacity i.e., emission reduction is proportional to the power demand of the site.

^l World Bank, "CO₂ Emissions (Kt) - Nigeria | Data," accessed September 7, 2023, <https://data.worldbank.org/indicator/EN.ATM.CO2E.KT?locations=NG>.



8.3 PROJECT EMISSION REDUCTION IN THE CONTEXT OF US/NIGERIA CLIMATE GOALS

KEY TAKEAWAYS

- Scaling the C&I DER business model will support Nigeria and the US in achieving climate and development targets.
- There are key barriers such as streamlining the supply chain of DER components that require proactive collaboration between the US and Nigerian governments to unlock the climate and development impacts highlighted in the sections above.

The project's climate and development impacts align with the US government's efforts to mitigate climate change and integrate climate considerations in its international engagements. They also support the US government's efforts, through USTDA as part of the Power Africa initiative— to encourage the installation of cleaner and more efficient electricity generation capacity across Africa. Power Africa's goal is to establish 30,000MW of new and cleaner power generation across sub-Saharan Africa. At scale, we estimate that the C&I business model can unlock 3,400 MW of clean electricity in Nigeria and has a replicable design for other countries with similar grid reliability challenges like those in Nigeria.

Beyond the direct increase in generation capacity from projects built under the C&I business model, the model will lead to equipment cost reductions in Nigeria by creating opportunities for bulk procurement and local participation for US-based suppliers in the DER equipment value chain, thereby driving increased adoption of solar PV generation across regions and customer segments. US-based suppliers of DER components and services have an opportunity to participate in developing the DER bulk procurement supply chain in Nigeria and boost trade between Nigeria and the US.

Power production accounts for 13% of energy related CO₂ emissions in Nigeria (about 14.3 million tons in 2020)^{li} and the estimated emission reduction

from scaling the business model to 170,000 C&I customers represents 19% reduction in power emissions. Scaling the business model therefore gets Nigeria closer to achieving the government's climate unconditional target of reducing overall emissions by 20% by 2030. The reduction in the use of generators will also reduce local air and noise pollution, improving quality of life for Nigerians.



09

IMPLEMENTATION PLAN



9.1 IMPLEMENTATION STEPS FOR PROJECTS

KEY TAKEAWAYS

- To prepare for project implementation, Daystar will share project proposals with customers, and work with them to make any necessary modifications to project designs, and update the final contract terms accordingly.
- Daystar will also collaborate with the DisCos throughout project development to ensure the final design is accepted by the DisCos. This will include validating the required grid upgrades, signing tripartite agreements, implementing distribution network upgrades, and managing system operations.

Implementation steps for the 20 project sites can be categorized into two main phases, pre-contract signing and post-contract signing. Details about key DisCo touchpoints involved in these

implementation steps and some individual site-specific considerations are also included in this section.

ⁱⁱ Climate Transparency, "Climate Transparency Report | 2020 Nigeria 2."



9.1.1 OVERVIEW OF IMPLEMENTATION STEPS

9.1.1.1 PRE-CONTRACT SIGNING



STEP 1

GRID UPGRADE STUDY VALIDATION

As part of this project, the RMI team and consultants, Afry, have completed studies to determine the most cost-effective way to upgrade the grid distribution network to improve reliability to each C&I customer. These studies were conducted alongside DisCo personnel, and the study reports, including the costs of network upgrades are found in the Final Grid Upgrade Reports^{lii}. Daystar will share the reports with the DisCo, get their alignment on the recommended upgrades, cost estimates and request approval to proceed with the upgrade costs for modelling and contract development. Daystar will also align with the DisCo on the number of hours of electricity supply that the DisCo can guarantee the customer. These available hours will be stated in the tripartite agreement. Daystar will also request the DisCos recommend vendors to implement the upgrades to meet their standards and specifications. Daystar can modify the Network Upgrade Brief Template provided in the Annex 9–A to engage the DisCos.



STEP 2

TRIPARTITE AGREEMENT UPDATES AND SIGNING

RMI has developed and aligned on tripartite agreement templates with DisCos that allocate the project's benefits, risks and responsibilities across all stakeholders. These templates can be found in Tripartite Agreement Templates.^{liii} Daystar may need to further negotiate the terms of the tripartite agreement with certain customers and DisCos

including the tariff, availability, reliability and underperformance clauses. Once the agreement has been reviewed and approved by all parties, Daystar will coordinate the tripartite signing of the agreement. The detailed steps involved in this process are:

a. Present Proposals to Customers

Daystar will share a proposal that includes proposed system design, blended tariffs, key next steps, expected timeline and key contract terms with the customer and request for feedback. Daystar can modify the Customer Proposal Template provided in the Task 9 closeout package to engage customers.

b. Finetune System Design

Once the customer shares feedback, Daystar will revisit and update the system design approach and technical configuration based on customer feedback and market availability of components.

c. Present final proposals to Customers and DisCos

Daystar will share a final proposal with the updated system design with the customer and the DisCo.

d. Update Contract

Daystar will update the contract terms based on project design changes and initial customer and DisCo feedback.

e. Align on Contract

Daystar will align on the updated contract terms with DisCo and Customers as needed.

f. Present Final Contract to Customer

Daystar will send the final proposal and contract to the customer to kick off the customer's internal signing process.

^{lii} Provided as deliverables under Task 2, whose close-out package includes the final grid upgrade study reports and data from the customer feeder assessment for all the customers. Also see Annex 2 of this report.

^{liii} Provided as a deliverable under Task 5, whose close-out package includes the final tripartite agreement templates agreed upon with DisCos. Also see Annex 5 of this report.



g. Contract Signing

Daystar will coordinate with DisCo and the customer to complete the signing of the tripartite agreement.

9.1.1.2 POST-CONTRACT SIGNING



STEP 3

REGULATORY APPROVAL

For projects less than 1MW that only serves one single customer and not selling excess generation to the grid or other customers, it's not required for Daystar to obtain a permit or license from NERC. However, involving NERC has its benefits. For example, NERC can intervene when disputes happen with DisCos and customers regarding payments. Besides, Daystar already have most of the required materials to apply for NERC approval, including the tripartite agreement and preliminary environmental and social impact assessments, so we do not expect it to be a heavy lift. For projects larger than 1MW, NERC approval is required. Section 4 of this report describes the process of the application in detail. Either way, this should not prevent Daystar from kicking off the deployment process of their assets, as regulatory approval can happen concurrent with Step 4 and Step 5.



STEP 4

FINANCING & PROCUREMENT

Daystar will coordinate the procurement of the DER components and grid upgrade components, then if applicable, the mobilization of DisCo-approved vendors who will do the grid upgrades.



STEP 5

CONSTRUCTION AND IMPLEMENTATION OF GRID UPGRADES

Daystar will oversee the grid upgrades and

construct the DER system at the client's facility. When network upgrades are completed, Daystar will test and measure the grid reliability and the overall system to ensure it works to the right quality.



STEP 6

OPERATIONS

Daystar and the DisCo will operate and maintain the project to meet the terms of the tripartite agreement.

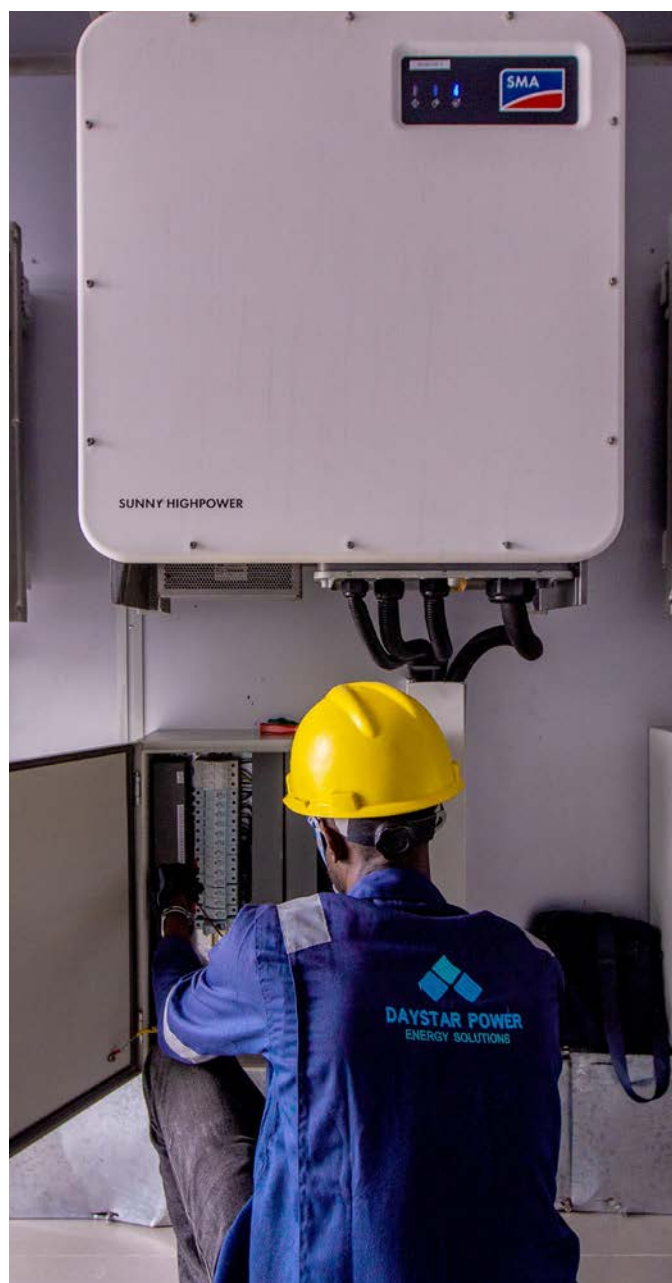


Figure 34 High-level implementation plans

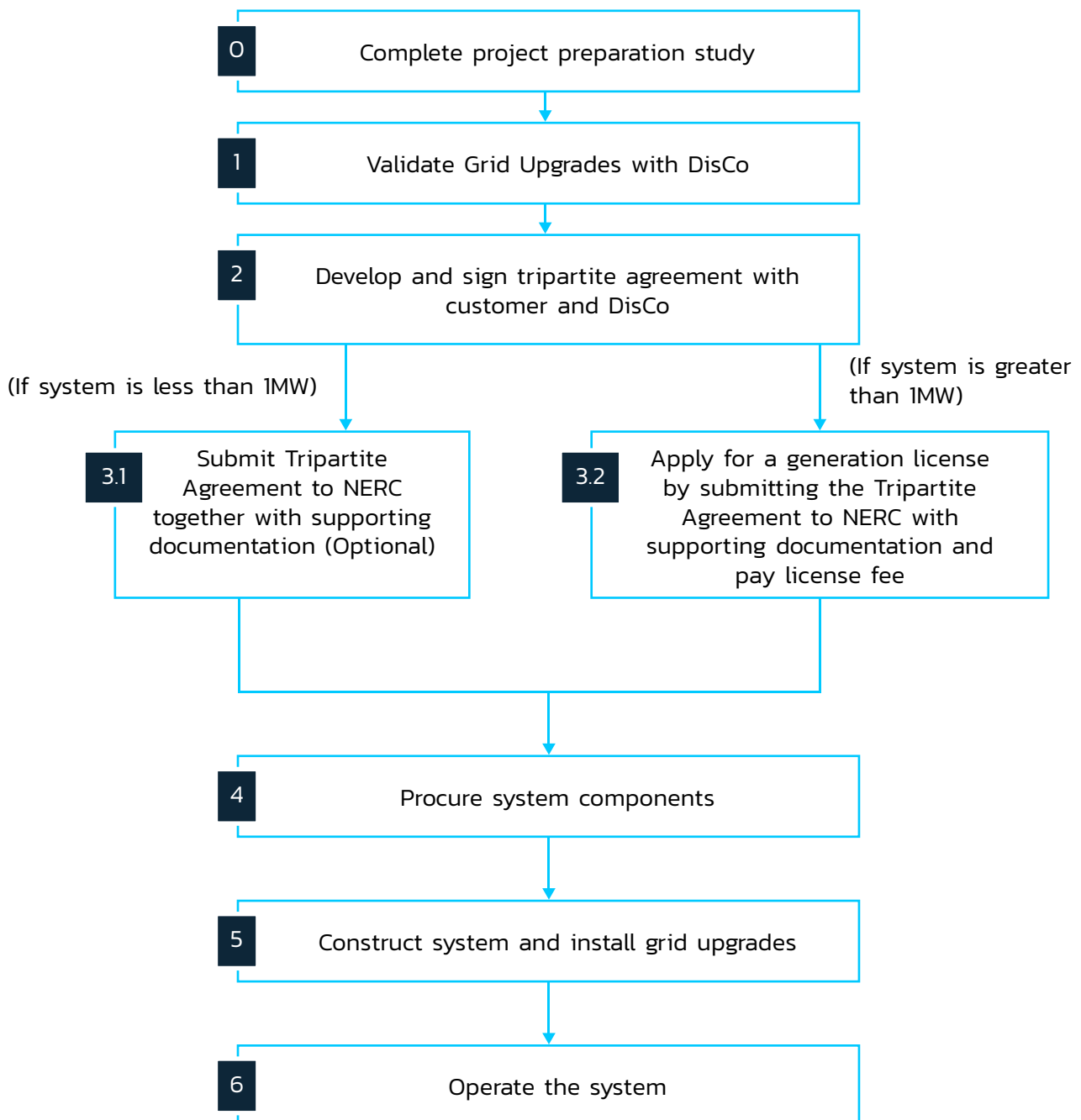




Table 50 High-level schedule of implementation milestones

S/N		MONTH 1	MONTH 2	MONTH 3	MONTH 4	MONTH 5	MONTH 6	MONTH 7	MONTH 8+
1	Grid Upgrade Validation								
2	Tripartite Agreement Review and Signing								
	Present Proposals to Customers								
	Finetune System Design								
	Update Contract								
	Align on Contract								
	Present Final Contract to Customer								
	Contract Signing								
3	Regulatory Approval								
4	Financing & Procurement								
5	Construction and Implementation of grid upgrades								
	Implementation of grid upgrades								
	PV System Construction								
	Battery System Integration								
6	Operations								
	Partial Operations								
	Full Operations								



9.1.2 DETAILS ABOUT THE DISCOS' INTERNAL APPROVAL PROCESSES TO ACHIEVE PROJECT COMMISSIONING AND KEY POINTS WHERE THE GRANTEE WILL NEED TO ENGAGE THE DISCOS

Daystar will need to engage the DisCos, who are key partners on the project, at the following key points towards project implementation.

1 GRID UPGRADE STUDY VALIDATION

- **FOR AEDC:** Daystar will send a network upgrade brief and network assessment report, when applicable, as a supporting document to the DER team^{lv} and request for a review and validation. These documents can be sent via email or as physical copies. The AEDC team will respond with their validation of the brief and share the number of hours of grid availability that AEDC can commit to for the customer under this business model. They will also share their feedback on the proposed cost and recommended vendors to carry out the grid upgrades.
- **FOR AEDC:** Daystar will send a network upgrade brief and network assessment report, when applicable, as a supporting document to the DER team^{lv} and request for a review and validation. These documents can be sent via email or as physical copies. The AEDC team will respond with their validation of the brief and share the number of hours of grid availability that AEDC can commit to for the customer under this business model. They will also share their feedback on the proposed cost and recommended vendors to carry out the grid upgrades.
- **FOR IE:** Daystar will send the network brief and network assessment report to the DER officer and the Bilateral team at IE.^{lv} The IE team will respond to the email providing the grid availability and any other comments on the brief and the report.

For all the DisCos, it is essential that Daystar get clarity on the recommended vendors to execute the network upgrade.

2 TRIPARTITE AGREEMENT UPDATES AND SIGNING

- **FOR AEDC:** Daystar will finalize the agreement through the DER team who will work closely with the assigned legal officer from AEDC. AEDC's Chief Business Officer^{lvii}, will act as the contact person in the contract, while AEDC's Chief Executive Officer^{lvii}, will sign the contract.
- **FOR EKEDC:** Daystar will engage the head of the business development team, to finalize the agreement. He will work closely with the legal and procurement teams to finalize the transaction. The agreement will be signed by EKEDC's Chief Executive Officer and the contact person for the contract will be the EKEDC's Head of Regulatory and Procurement.
- **FOR IE:** Daystar will work with the bilateral team to finalize the agreement with Osama Osakue, who is responsible for C&I transactions. The contact person in the agreement will be IE's Head of the Bilateral team, and IE's CEO^{lviii}, will sign the agreement.

3 SUPPORT DISTRIBUTION NETWORK UPGRADES

- **FOR AEDC:** Daystar will work with DER team, to facilitate the implementation of distribution network upgrades with the customer's area/district manager and linesmen responsible for the operations and maintenance of the customer feeder.
- **FOR EKEDC:** Daystar will work with the head of the business development team who will assign technical personnel from EKEDC's head office with the support from the selected business unit to support the implementation of distribution network upgrades.

- For IE: Daystar will work with DER officer who will facilitate the implementation of the distribution network upgrades with the customer's area manager and linesmen responsible for the operations and maintenance of the customer feeder.

4 OPERATIONS

- DisCos will send a post-paid invoice to Daystar at the end of each month via their typical billing process from the DisCo area office responsible for the customer. Daystar will work with the DER team leader or DER officer at the DisCo and the area office to ensure the DisCo operates and maintains the system and customer connection to meet grid availability standards.

9.1.3 SITE-SPECIFIC IMPLEMENTATION CONSIDERATIONS

Daystar needs to consider site-specific factors before project implementation for certain customers. These factors are described below:

- [REDACTED] – Our analysis indicates a mismatch between [REDACTED] energy consumption and their current billing from AEDC. While the customer is interested in a utility-enabled solution, they will want clarity and all potential issues addressed before proceeding with a solution. Without this, the [REDACTED] management team has expressed that they will likely not move forward with a solution and may consider full grid defection if problems persist. Daystar should support AEDC to investigate the energy consumption issue by comparing the customer bills against

feeder availability, install a data logger for the customer to verify the energy being read by their energy meters, and investigate the customer connection for energy theft.

- [REDACTED] – Daystar should coordinate the AEDC to ensure grid upgrades are effectively implemented and conduct any further studies to identify and resolve the power quality issues faced by [REDACTED] that has led to total grid defection. Daystar should work on re-engaging [REDACTED] to revive their interest in the project.
- [REDACTED] – Daystar should engage EKEDC to conduct a grid upgrades assessment and effectively manage the relationship with them. It is important to communicate the project's value proposition, emphasizing that the DER solution can be implemented quickly as a temporary fix before EKEDC implements solutions for the bulk grid.
- [REDACTED] – Daystar should effectively manage the relationship with EKEDC and the customers. It is important to communicate the project's value proposition, emphasizing that the DER solution can be implemented quickly as a temporary fix before EKEDC implements solutions for the bulk grid.



^{lv} Tobi Olutayo is the current head of business development at EKEDC.

^{lvi} Current members of IEs Bilateral Team include Obianuju Ukwueze, Head of Bilateral Team, OUkwueze@ikejaelectric.com; Osama Osakue who is responsible for IEs C&I portfolio, OsamaOsakue@ikejaelectric.com; and the DER officer, Odunayo Onafuye, Odunayo.Onafuye@abujaelectricity.com

^{lvii} AEDC's current Chief Business Officer and Chief Executive Officer are Sani Usman and Christopher Ezeafulukwe respectively

^{lviii} IE's current CEO is Folake Soetan



9.2 SITES PRIORITIZATION MATRIX AND PROPOSED IMPLEMENTATION SCHEDULE

KEY TAKEAWAYS

- The 20 project sites are categorized into four groups based on their readiness for implementation. We recommend implementing them in tranches to simplify some processes, such as DisCo engagement and regulatory approval.
- High-priority customers in AEDC territory (Tranche 1) should be prioritized for rapid implementation.

The project team has evaluated the 20 projects using four criteria based on their readiness for implementation and recommends implementing them in tranches based on ranking for priority against the criteria. The criteria used for ranking the sites are:

1. CUSTOMER FIT FOR THE BUSINESS MODEL (BM FIT)–

All commercial and industrial customers have been assessed under a combination of key parameters to determine whether or not they are a good fit for the business model. Customers with high electricity demand, significant daytime electricity use, physically appropriate sites for DERs, ease of grid integration and minimal hours of grid supply score highly against this criterion.

2. CUSTOMER INTEREST

The project team has gauged the interest of all commercial and industrial customers based on our engagement with them. Customers who have shown high enthusiasm for the DER solution in in-person meetings and have had regular follow ups, are willing to sign a long-term contract and have actively shared data on projects score highly against this criterion.

3. CUSTOMER SAVINGS

Based on the DER system financial models, projects are evaluated based on the expected savings for each customer. Customers that the solution shows a greater than 20% savings score highly against this criterion (also see Task 3 Report for details).

4. DISCO'S INTEREST

The project team has gauged the interest of each DisCO in collaborating with each of the 20 customers. Customers who the DisCos have shown strong interest and traction in pursuing project implementation score highly in this criterion.

The tables below show the proposed implementation tranches based on the prioritization matrix, and a master schedule of events for the implementation of all tranches and sites. Daystar should prioritize the first two tranches of sites with medium to high customer interest, and high interest and readiness across the two DisCos, IE and AEDC. High-priority customers in AEDC territory should be prioritized for rapid implementation.



Table 51 Proposed Implementation Tranches

TRANCHE 1 (AEDC CUSTOMERS)

CUSTOMER	BM FIT	CUSTOMER INTEREST	CUSTOMER SAVINGS	DISCO'S INTEREST
[Customer 1]	High	High	High	High
[Customer 2]	High	High	Low	High
[Customer 3]	High	High	High	High
[Customer 4]	High	High	High	High
[Customer 5]	Medium	High	Medium	High
[Customer 6]	High	High	Medium	High

TRANCHE 2 (IE CUSTOMERS)

CUSTOMER	BM FIT	CUSTOMER INTEREST	CUSTOMER SAVINGS	DISCO'S INTEREST
[Customer 13]	High	High	High	High
[Customer 14]	Medium	Medium	Low	High
[Customer 15]	High	Medium	Medium	High
[Customer 16]	High	Medium	High	High
[Customer 17]	High	Medium	Low	High

TRANCHE 3 (AEDC CUSTOMERS)

CUSTOMER	BM FIT	CUSTOMER INTEREST	CUSTOMER SAVINGS	DISCO'S INTEREST
[Customer 7]	High	Medium	High	High
[Customer 8]	High	Medium	Low	High
[Customer 9]	High	Low	High	High
[Customer 10]	High	Low	High	High
[Customer 11]	High	Medium	Medium	High

TRANCHE 4 (EKEDC CUSTOMERS)

CUSTOMER	BM FIT	CUSTOMER INTEREST	CUSTOMER SAVINGS	DISCO'S INTEREST
[Customer 18]	High	High	High	Low
[Customer 19]	High	Medium	High	Low
[Customer 20]	High	Medium	Low	Low
[Customer 21]	High	Medium	Medium	Low

Table 52 Master Schedule of Events

	AUG-23	SEP-23	OCT-23	NOV-23	DEC-23	JAN-24	FEB-24	MAR-24	APR-24	MAY-24	JUN-24	JUL-24	AUG-24	SEP-24	OCT-24	NOV-24	DEC-24+
Tranche 1 sites																	
Grid Upgrade Validation																	
Tripartite Agreement Review and Signing																	
Regulatory Approval																	
Financing & Procurement																	
Implementation of grid upgrades																	
System Construction																	
Operations																	
Tranche 2 sites																	
Grid Upgrade Validation																	
Tripartite Agreement Review and Signing																	
Regulatory Approval																	
Financing & Procurement																	
Implementation of grid upgrades																	
System Construction																	
Operations																	
Tranche 3 sites																	
Grid Upgrade Validation																	
Tripartite Agreement Review and Signing																	
Regulatory Approval																	
Financing & Procurement																	
Implementation of grid upgrades																	
System Construction																	
Operations																	
Tranche 4 sites																	
Grid Upgrade Validation																	
Tripartite Agreement Review and Signing																	
Regulatory Approval																	
Financing & Procurement																	
Implementation of grid upgrades																	
System Construction																	
Operations																	

9.3 FINANCING ARRANGEMENTS AND PROCUREMENT OF GOODS AND SERVICES

Daystar is well capitalized to implement these projects and does not require additional financing at this stage. The C&I project team should include the project costs for all derisked sites as part of the company's annual budget for capital prioritization.

As part of the tranching deployment approach, RMI recommends that Daystar procure the major equipment, particularly the Battery Energy Storage

systems, in tranches to take advantage of bulk procurement discounts and foster the interest of potential suppliers that prefer to import components at large scale. They should also continue to engage the U.S. suppliers outlined in the Section 6 since some of the interested suppliers quoted manufacturing supply chain delays as a tentative reason for not supplying to Nigeria currently, which is an evolving situation.

9.4 RECOMMENDED APPROACH FOR THE GRANTEE'S ORGANIZATION OF THE PROJECT

KEY TAKEAWAYS

- RMI recommends that a designated person or unit within the Daystar team oversees the major touchpoints with the DisCos in the implementation of these projects.
- There are only minimal changes to roles and resources spent to execute this business model compared to Daystar's existing business models.

RMI recommends the creation of a Utility-Enabled Distributed Energy Solution (UEDES) team lead within Daystar's Business Development team who will maintain the relationship and communication with DisCos, oversee the major touchpoints with the DisCos, maintain C&I customer communication

and manage project execution. The table below summarizes the existing roles and resources spent to execute Daystar's current business models and additional roles and increase in resource and capacity allocation of Daystar's functional teams to execute projects under this business model.





Table 53 Roles and Responsibilities of Daystar's functional teams to execute projects under this business model.

DAYSTAR FUNCTIONAL TEAM	ROLE IN EXECUTING PROJECTS UNDER EXISTING DAYSTAR BMS	RESOURCE AND CAPACITY SPENT ON EACH PROJECT.	ADDITIONAL ROLE IN EXECUTING PROJECTS UNDER THIS BM.	INCREASE IN RESOURCE AND CAPACITY SPENT ON PROJECTS UNDER THIS BM
Business Development (BD)	Identify potential markets and clients. Build relationships and maintain client communication while overseeing projects from design to installation.	[REDACTED]	Builds and maintains relationships and communication with DisCOs, oversees contract development and signing. RMI recommends the creation of a UEDES lead on the BD team	10% to 20% increase in time spent
Sales and Design Engineering	Leads system design, techno-economic modelling, and proposal development	[REDACTED]	Works with DisCo to conduct grid upgrade studies for new projects under this BM	5% to 10% increase in time spent
Legal	Ensure legal compliance and permits. Handle contracts and agreements. Address regulatory issues.	[REDACTED]	Applies for minigrid license/ NERC approval of Tripartite agreement for projects less than 1 MW project (Minigrid) and for projects greater than 1MW, generation license.	Significant increase in timeline for projects less than 1MW
Procurement	Source suppliers and negotiate contracts. Manage equipment acquisition and delivery. Ensure quality and manages logistics	[REDACTED]	Negotiates contract with contractors to implement grid upgrades	Less than 5% increase in time spent
Project Engineering	Implementation and execution of design systems	[REDACTED]	Validates the installation of grid upgrades and grid performance before full system operation	Less than 5% increase in time spent



DAYSTAR FUNCTIONAL TEAM	ROLE IN EXECUTING PROJECTS UNDER EXISTING DAYSTAR BMS	RESOURCE AND CAPACITY SPENT ON EACH PROJECT.	ADDITIONAL ROLE IN EXECUTING PROJECTS UNDER THIS BM.	INCREASE IN RESOURCE AND CAPACITY SPENT ON PROJECTS UNDER THIS BM
Field Service and NOC Team	Continuous monitoring, operation, and maintenance	[REDACTED]	Operation of system in collaboration with DisCo.	Less than 5% increase in time spent

9.5 KEY PROJECT IMPLEMENTATION RISKS AND MITIGATION STRATEGIES

KEY TAKEAWAYS

- Effective stakeholder management is crucial to mitigate regulatory, customer or DisCo apathy and schedule risks.

RMI has conducted a preliminary risk assessment for the implementation of these projects, identifying potential risks that could inhibit the successful and timely completion of the projects and developed strategies to lessen the negative impact of these

risks. Below is a list of the principal external risks identified as having a combination of a reasonable likelihood of occurrence and significant negative impact to the implementation of these projects.

Table 54 Key Project Implementation Risks and Mitigation Strategies

RISKS	DESCRIPTION	MITIGATION
Political Risk	Risk that changes in government priorities lead to high impact changes in DisCos leadership & interest in business models.	Throughout the project, the team has worked closely with DisCos to communicate the value proposition, align the business model with the DisCos' interests and strategies, and generate support for implementation. If there is a change in DisCo leadership, RMI and Daystar will use their strong relationships with key stakeholders at the DisCos to ensure project implementation continues smoothly.
Regulatory Risk	Risk that projects deployment or operation is hindered due to opposing policy or regulatory action.	The project team has conducted a rigorous regulatory assessment to ensure adherence to the existing regulatory framework. The RMI team engaged the regulator, NERC extensively over the course of the project and has supported the Daystar leadership team in further engagement to ensure project deployment support. Daystar should continue to manage the relationship with NERC to ensure project implementation continues smoothly.



RISKS	DESCRIPTION	MITIGATION
Customer scepticism	Risk that project deployment is hindered due to high level of risk aversion around power supply of potential large customer and industrial customers.	The project team have engaged extensively with customers in designing the DER systems to improve their power reliability and reduce their cost. Daystar should manage customer relationships effectively, proactively addressing customer concerns as they arise. Daystar should effectively communicate their track record of deploying similar systems to commercial and industrial customers across various geographies.
DisCo capacity	Risk that project deployment is hindered due to inadequate capacity of the DisCos including limitations on staff strength, ability to meet power supply requirements	RMI, through other initiatives would support DisCos in creating processes and allocating staff time to supporting the implementation of these projects. Daystar should manage the relationships with DisCo stakeholders effectively and ensure the value proposition of each project to the DisCo is well communicated.
Tension between parties	Risk that on one or more of the parties: Customer, Daystar and DisCo are uncomfortable with terms of tripartite agreement	Daystar should manage customer and DisCo relationships effectively, proactively addressing customer concerns as they arise. Daystar should be flexible in making changes to the project and agreement structure in the spirit of ensuring a win-win-win for all parties.
Schedule risk	Risk that project deployment timeline is too long for Daystar or customer	Daystar should prioritize rapid implementation for the highly qualified projects based on the site prioritization matrix.
FX policy	Risks that the change in foreign exchange policy and naira devaluation against foreign currencies worsens project economics	Daystar should highlight the project cost savings and improved reliability when engaging customers.
Customer apathy	Risks that customer is no longer interested in pursuing project to implementation	Daystar should manage customer relationships effectively, proactively addressing customer concerns as they arise. Daystar should ensure the value proposition of each project to the customer is well communicated.
DisCo apathy	Risks that DisCo is no longer interested in pursuing project to implementation, due to potential change in DisCo strategy	Daystar should manage the relationships with DisCo stakeholders effectively and ensure the value proposition of each project to the DisCo is well communicated. In projects where DisCos have chosen to go a different direction, e.g., by pursuing an embedded generation solution for an area, Daystar should leverage the fact that the distributed energy solution can be implemented quickly and can be a temporary fix while the DisCo implements solutions for the bulk grid.

9.6 PROJECT MONITORING AND EVALUATION, AS WELL AS THE PROCESS FOR INCORPORATING LESSONS LEARNED

KEY TAKEAWAYS

- Daystar should track key data points such as the number of projects deployed, project diesel usage, power reliability to customer to determine if the projects meet its intended goals.
- Daystar should maintain a healthy and collaborative relationship with the DisCo in the implementation and operation of projects, which can lead to an increase in project pipeline.

Monitoring and evaluating the implementation of the projects will allow Daystar to ascertain the success of this BM as well as incorporate lessons learned and determine if the program meets its intended goals. Some project goals, how they will be measured and how lessons learned will be incorporated in future project are described below.



NUMBER OF DEPLOYED PROJECTS

From the 20 derisked projects, Daystar should track how many of the projects get deployed, reasons for the projects not getting deployed and include the lessons learned in future business development activities for projects under this business model.



REDUCED DIESEL USAGE ON PROJECTS

Daystar using its energy management platform, should track diesel usage on projects under this business model and compare them against other Daystar business models as well as expected diesel usage from dispatch models on this project.



INCREASED PROJECT RELIABILITY

Daystar using its energy management system, should measure reliability provided to the customer to ensure it is meeting the reliability standards on

the tripartite agreement. With guaranteed reliable supply from the grid, Daystar should evaluate the reliability and cost implications of providing the level of reliability and compare it to business as usual for the customer and other existing Daystar projects.



IMPROVED RELATIONSHIP WITH DISCO

Daystar should maintain a healthy and collaborative relationship with the DisCO in the implementation and operation of these projects. Daystar should see an increase in opportunities for collaboration with the DisCos on other projects as a result of this improved relationship.



INCREASED CUSTOMER SATISFACTION

Daystar should measure customer satisfaction by keeping track of customer complaints and ensuring these complaints are resolved promptly.

For all these project goals, Daystar should ensure lessons learned are implemented when pursuing other non-derisked projects under this business model. Daystar should share the lessons learned on these projects through regular progress share-outs with RMI as well as the Daystar management teams.

10

LIST OF ANNEXES



Annexes are provided in separate documents and can be available upon request.



- Annex 1-A: Work Plan
- Annex 1-B: Task 1 Close-Out Summary Slides
- Annex 2-A: Customer Data Collection Form Template
- Annex 5-B: Contract Templates
- Annex 6-A: List of Identified U.S. Suppliers
- Annex 6-B: U.S. Supplier Engagement Summary Notes
- Annex 9-A: Network Upgrade Brief Template

