Floating Solar PV Project in the Philippines

Assessment of Levelised Cost of Energy

12 November 2024

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Issue and Revision Record

Revision	Date	Originator	Checker	Approver	Description
A	23 Aug 24	A. Lee N. Ariyaphonphiroon N. Janampansang P. Hiranphattararoj S. Thitipankul B. Rojrungruengkit C. Pama	J. Srisuk K. Sirawitoon P. Mulpruek	M. Jasinski	Draft report
B	9 Oct 24	P. Sikaewkhong N. Janampansang	J. Srisuk K. Sirawitoon S. Thitipankul P. Mulpruek	M. Jasinski	Second draft report
C	25 Oct 24	S. Thitipankul	J. Srisuk K. Sirawitoon P. Mulpruek	M. Jasinski	First final report
D	30 Oct 24	J. Srisuk	J. Srisuk	M. Jasinski	Updated first final report
E	12 Nov 24	J. Srisuk	J. Srisuk	M. Jasinski	Updated first final report revision 2

Document reference: 605100188-001 | 01 | E |

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Executive Summary

Mott MacDonald was engaged by the Client as the technical advisor to perform a technical assessment of a reference floating solar PV ("FPV") scheme. The assessment was based on an analysis of three selected sites in the Philippines, collectively referred to as the 'Projects' and individually as the 'Project'. To perform the study, Mott MacDonald collaborated with SunAsia Energy Inc., AC Subic Solar Inc., and SNAP Magat, all of which are members of the Philippine Solar and Storage Energy Alliance (PSSEA).

Introduction

Our assessment focuses on three key areas:

1. Energy Yield Analysis (EYA);
2. CAPEX and OPEX estimate based on cost benchmarking; and
3. Assessment of the Levelised Cost of Electricity (LCOE)

The three sites have been selected to reflect the diversity of site conditions and designs for FPV projects under development in the Philippines. Summary of the sites' information are presented in Table E.1.

Table E.1: Site locations

Project name and assumed DC capacity	Location and coordinates	Project type	General site characteristics
Laguna Bay 139.8 MWp	Luzon 14.2118°, 121.2739°	FPV – Pure float (Dome configuration)	The Project will be located on Laguna Lake, regulated by the Laguna Lake Development Authority (LLDA) up to 4.5 km from the shore. Laguna Lake has significant variation in water depth, ranging from 1.1 m to 4.6 m, and wave heights approximately ranging from 1.8 m to 3.0 m, with certain blocks experiencing waves up to 8 m.
Sagay 126 MWp	Western Visayas 10.9405°, 123.3919°	Stilt-mounted aquavoltaic on fishpond (South-facing)	The area is noted to be a fishpond located along the Himugaan river delta in Sagay, Negros Occidental. The bathymetry and water levels at the Project site have not been assessed in this study. Based on the site elevation profile available in the satellite imagery software, the Project has flat topography; therefore, we assume that the mounting structure can be installed without requiring grading.
Magat 126.3 MWp	Luzon (Magat Dam) 16.8241°, 121.4527°	FPV – Membrane type (Flat positioned)	The Project will be located inside the Magat dam reservoir (i.e., Magat Hydroelectric Power Plant) which is located along the Magat river. Based on information available, the water depth at the Project reaches up to 30m with water level variations ranging from approximately 165 height above msl to 190 height above msl.

Source: The Client

Key Technology pre-selection

We have considered monocrystalline silicon (Mono-c-Si) for its higher energy conversion efficiency relative to polycrystalline and thin-film technologies, noting that its overall yield benefit is generally expected to outweigh any higher costs. We have selected N-Type TOPCon half-cut with bifacial (dual-glass) technology, with Jinko Solar (66HL4M-BDV) as the representative PV module model for the assessments.

For the purpose of the EYA and LCOE assessment, a central inverter has been selected due to its stronger track record in FPV applications in the region. We have considered Sungrow SG4400UD-MV as the representative central inverter model for all Projects.

For the floating platform in Laguna Bay, we have selected the pure float type, considering its common use and strong track record. The advantages of simple assembly, installation, and scalability are beneficial for the GWp-scale of the Project. Given the windy conditions at the Project location, a dual-pitch PV array design is typically adopted to reduce wind drag. Only manufacturers of pure float types offer the dual-pitch design, so we have selected the pure float structure with Sungrow SGF-TS30 as the representative floaters model.

For Sagay, the Client has already selected a stilt-mounted structure with a south-facing azimuth. This type of structure, comprising piles and racks instead of floating systems that experience dynamic movement from water. The stilt-mounted structure on water would still require additional design, installation, and operational requirements (e.g., elevated MV stations, draining water from the installation area, use of high-powered specialist equipment and labour).

For Laguna and Magat, the design of anchoring and mooring systems depends on site-specific conditions (e.g., water level variation, bathymetry, soil conditions, environmental impact). Detailed studies will be required to assess the specific requirements of these components, as floating platform suppliers typically recommend the appropriate anchoring and mooring types for their designs.

Energy Yield Analysis

The EYA for the Projects has been carried out based on documentation received from the Client and available information. The performance of the plant is influenced by the choice of selected technologies, design, and environmental conditions. The specific yield has been calculated to determine the annual yield estimates of the Projects. The specific yield is the product of the Global Inclined Irradiation (GII) and the Performance Ratio (PR) of the plant. The summary of plant performance, GII, and yields is presented in the Table E.2.

Table E.2: Summary of yield estimates at P50

Parameters	Laguna Bay	Sagay	Magat
Equivalent GII (kWh/m^2)	1,766.5	1,908.4	1,861.4
Initial PR (%)	83.3%	84.3%	87.0%
Initial Specific Yield (kWh/kWp/year)	1,471.1	1,608.5	1,620.2
Energy (MWh) at year 1	205,090	202,128	204,145
Energy (GWh) over 20-year period	3,906	3,850	3,888

Source: Mott MacDonald

CAPEX and OPEX based on cost benchmarking

The cost has been analysed for CAPEX and OPEX. Within each cost category, we have provided a high-level breakdown of the associated cost items as a range shown in U.S. Dollars (USD) per kW of installed peak power, excluding taxes and VAT. Given that project-specific cost items can vary significantly based on site characteristics, logistic strategies, and selected technologies, our estimation is based on the current market condition and does not account for industry changes and economic factors during the construction phase of the Projects. Project-specific costs, including land acquisition and extensive land preparation works (such as unforeseen lakebed preparation, onshore cut and fill volumes, slope stability protections, and flood defences), are not considered in the cost benchmarking under this section but have been considered in the LCOE assessment.

Since FPV technology is still in its early stage, limited information is available in the public domain discussing O&M costs and OPEX requirements. Therefore, we discuss the global trends related to utility-scale PV projects in this section. According to IRENA's 2022 report, the O&M costs of utility-scale solar PV plants have declined in recent years due to several factors:

- Improvements in module efficiency have reduced the surface area required per MW of capacity.
- Improvements in the reliability of the technology have resulted in systems optimized to reduce O&M costs.
- Innovations such as robotic cleaning and 'big data' analysis, which enable preventative interventions ahead of failures, have driven down O&M costs and reduced downtime.

NREL found that historically reported data shows a correlation between OPEX and CAPEX reductions. From 2011 to 2021, average OPEX and CAPEX costs fell by 58% and 73%, respectively. They forecast that until 2050, property-related expenses will be reduced by the inverse ratio of the increase in module efficiency, which reduces the space and number of modules required.

The benchmark O&M costs for utility-scale PV plants in Southeast Asian countries are reported to be in the range of 6-25 USD/kW/year, with an average of 15.4 USD/kW/year. The cost benchmark presented is based on our FPV project experience in Asia and solar PV projects in the Philippines, showing a CAPEX range of 670 – 1,260 USD/kWp with an average of 945 USD/kWp and an OPEX range of 10 – 25 USD/kWp with an average of 18 USD/kWp. The cost benchmark of HV transmission line and works at the connection point are provided separately from the CAPEX.

It is suggested that the FPV CAPEX specific to the Philippines be assumed in the mid to higher range given challenging wind load conditions, which would prompt more stringent requirements on the design and engineering of structural components for the required reliability and more frequent inspection and maintenance.

For other types of technologies considered by the Client outside of typical pure/HDPE floats:

- Membrane type floating structures are claimed to be on the lower end based on the public domain, attributable to ease of transportation compared to typical floater solutions. Given the immaturity of the technology, more data would be required to validate this information from the public domain.
- Stilt-mounted aquavoltaics, which represent a unique variation of solar PV projects installed over water bodies, such as fishpond or inter-tidal area. Unlike traditional floating solar installations, these systems do not require anchoring, mooring, or floaters. Instead, they rely on bottom-fixed mounting structures and high-powered specialist installation equipment, which influences their cost profile. The primary cost components include materials for the mounting structures and the labour and specialist equipment needed for installation.

The typical CAPEX and OPEX contingency are suggested at 3% - 5% and 5% - 10%, respectively, and a Maintenance Reserve Account of 2% of the inverter cost per year during the 25-year operational period is recommended in line with requirements for projects applying for financing from international lenders.

Levelised Cost of Electricity

The LCOE model used in this assessment is a simplified model that does not consider financing and taxation-related parameters. The figures used in the study are based on assessments outlined in preceding sections—namely, the Energy Yield Assessment and cost benchmarking. Consequently, the resulting LCOEs are subject to the limitations and assumptions discussed in those sections.

We applied the key technical and cost assumptions for each of the cases modelled to the “Official NREB - Solar Financial Model - GEAP Model.xlsx” (“GEAR Model”), which is understood to be the basis for the GEAR price evaluation. This was done to account for any financing parameters (e.g., debt and equity, taxation) captured in the GEAR Model for comparison purposes.

We highlight that we have not independently verified any assumptions, applications, or financial statements generated in the GEAR Model for accuracy or conformance with relevant Generally Accepted Accounting Principles (GAAP).

Table E.3 presents the resulting LCOE, noting that this is based on the Projects’ energy yields at a probability of exceedance at P50. We also highlight that the LCOE figures in Table E.4 are the results from the simplified LCOE model, which does not take into account financing and taxation parameters and therefore the LCOE figures are further subject to such parameters.

The LCOEs ranges at **5.3923 – 6.5286 PHP/kWh** (pre taxation and financing parameter) as presented in the Table below.

Table E.3: LCOE results from LCOE Model

Cases	LCOE results (PHP/kWh)		
	LLDA	Sagay	Magat
Base Case	6.3364	5.5295	5.3923
Upside Case	6.1988	5.4124	N/A
Downside Case	6.5286	5.5723	5.8027

Source: Mott MacDonald

Further to that, we have attempted to input the key parameters from our assessment (i.e., CAPEX and OPEX estimates, energy yields) into the “Official NERM – Solar Financial Model – GEAP Model.xlsx” for reference. The LCOEs ranges at **6.2556 – 7.2693 PHP/kWh** (incorporating taxation and financing parameter). The results of the LCOE figures upon using the GEAR Model are summarised in Table E.4.

Table E.4: LCOE results from GEAR Model

Cases	LCOE results (PHP/kWh)		
	LLDA	Sagay	Magat
Base Case	7.1074	6.3776	6.2556
Upside Case	6.9901	6.2753	N/A
Downside Case	7.2693	6.4148	6.6125

Source: Mott MacDonald based on GEAR Model

It is worth highlighting that the GEAR Model has also take into consideration the “Feed-in-Tariff” assumptions for the calculation of the resulting tariff (where deviation in that appears to have impact on the financing parameter e.g. WACC) however, we have not adjusted such figure under this assessment and left as originally assumed in the GEAR Model (i.e. 5.9480 PHP/kWh).

Further to the LCOE evaluation, we have conducted a comparative analysis on between the LCOE results under this study and the Green Energy Auction Reserve (GEAR) price for the second round of auction as established by the Energy Regulatory Commission (ERC) in the Resolution No.06 ("GEAR Price Resolution").

The results show that for considered cases based on the GEAR Model, the LCOE results are higher than the currently proposed GEAR Price of 5.3948 PHP/kWh. We note that the main difference in the assumption under the two models are the OPEX costs and the assumed capacity factor. The sensitivity analysis revealed that the primary factors impacting the LCOE figures are the parameters related to estimated generation, such as capacity factor and probability of exceedance cases.

Introduction

Mott MacDonald was engaged by the Client as the technical advisor to perform a technical assessment of a reference floating solar PV ("FPV") scheme. The assessment was based on an analysis of three selected sites in the Philippines, collectively referred to as the 'Projects' and individually as the 'Project'. To perform the study, Mott MacDonald collaborated with SunAsia Energy Inc., AC Subic Solar Inc., and SNAP Magat, all of which are members of the Philippine Solar and Storage Energy Alliance (PSSEA).

Our assessment focuses on energy yield analysis ("EYA"), cost benchmarking, and assessment of the Levelised Cost of Electricity ("LCOE"). The three locations for the Project under this study include as outlined in Table 2.5 in accordance with our agreed scope of services and information confirmed by the Client.

Table 2.5: Site locations

Location	Project name	Project type	Representative coordinate
Luzon	Laguna Bay	FPV – Pure float (Dome configuration)	14.2118°, 121.2739°
Western Visayas	Sagay	Stilt-mounted aquavoltaic on fishpond (South-facing)	10.9405°, 123.3919°
Luzon (Magat Dam)	Magat	FPV – Membrane type (Flat positioned)	16.8241°, 121.4527°

Source: The Client

1.1 Methodology

In accordance with the agreed scope of works, the study approach and methodology for the assessment is undertaken with steps as outlined below:

- **Key technology pre-selection** – key technologies for the FPV will be assessed under this study – PV module, inverter, and floater. This report outlines the types of each technology available in the market and further takes into account the site/project characteristics to assess the suitability for each type of technology.
- **Plant configuration and design assumption** – plant design assumption will take into consideration site/project characteristics, limitation within the area, as well as the Mott MacDonald experiences for similar types of projects within the region.
- **Solar Resource Assessment ("SRA")** – this report outlines the available solar resources and their limitations.
- **Indicative Energy Yield Assessment ("EYA")** – the EYA is the key assessment for the Project's energy yield over its lifetime for which will be further utilised for the assessment of the Project's LCOE.
- **Cost benchmarking** – cost benchmark will provide the range of cost for the Project. This benchmark will be broken down into EPC costs, O&M costs, key technology costs, and typical contingency. This will be based our FPV experiences in the Philippines and Asia Pacific, information publicly made available, and information provided by the Client.
- **Levelised Cost of Electricity ("LCOE")** – LCOE will be assessed based on the results of indicative EYA, and cost benchmarking. The resulting LCOE will include nine (9) cases following the results from the EYA.

1.2 Limitations

This study is undertaken with the objective to assess the representative capacity factor and LCOE of the floating solar PV projects in the Philippines which will be based for the three representative site locations provided by the Client. While the study aims to take into account site-specific conditions, we highlight that the study is on a representative level i.e. taking into account overall characteristics or conditions relevant to projects in the Philippines as opposed to focus on project-specific level. And therefore, the assessment under this report does not necessarily constitute a project's specific feasibility study for either of the three representative projects.

Furthermore, based on our scope of services, the results in this study is further subject to the assumptions and limitations as follows:

- The technology selection which is further used for the energy yield assessment was done on the representative level which we highlight that this is further subject to assessment of site conditions i.e. climate conditions, water bodies condition (bathymetry studies).
- The plant's configuration under this study was based on the high-level understanding of the type of water bodies for each of the representative location and our experiences for similar type of projects in the Philippines. This configuration does not consider an indicative design for the Project nor is the optimisation exercise.
- Due to limited information regarding grid connection arrangements, we have assumed a typical configuration at this stage. We note that the lack of supporting information will affect the accuracy of transmission line loss in the Energy Yield Assessment (EYA) as well as the Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) estimations.
- Limited data is available from the large scale FPV projects in the Philippines to date and the cost benchmark provided have been based on our FPV project experience in Asia and solar PV projects in the Philippines.
- The cost benchmarks do not factor in any industry change, supply chain maturity especially for the floating system, which is relatively new in the country, or economic factors that may occur during project development;
- Under the cost benchmark exercises land acquisition and major land/lakebed preparation activities, right of way or clearing prior to construction, taxes or VAT and customs are deemed to be dependent on project-specific location as well as requirements for grid connection may vary.
- The LCOE under this assessment is based on a simplified LCOE model where the financial and taxation related parameters are not considered.
- The results from the GEAR model presented in this report are provided for references where the result is based on the accuracy and correct application of the assumption within the model. We have not independently verified any assumptions, application and/or financial statement generated in the GEAR Model either on its accuracy or conformance with relevant Generally Accepted Accounting Principles (GAAP).

2 Project Description

2.1 Overview

This section outlines general overview of the site locations based on the desktop review of the information made available by the Client. The objective to this section is to provide an overview of key site characteristics and location for the three locations provided by the Client.

2.2 Key site characteristics

The key characteristics of the two site locations are summarised in Table 2.1.

Table 2.1: Key site characteristics

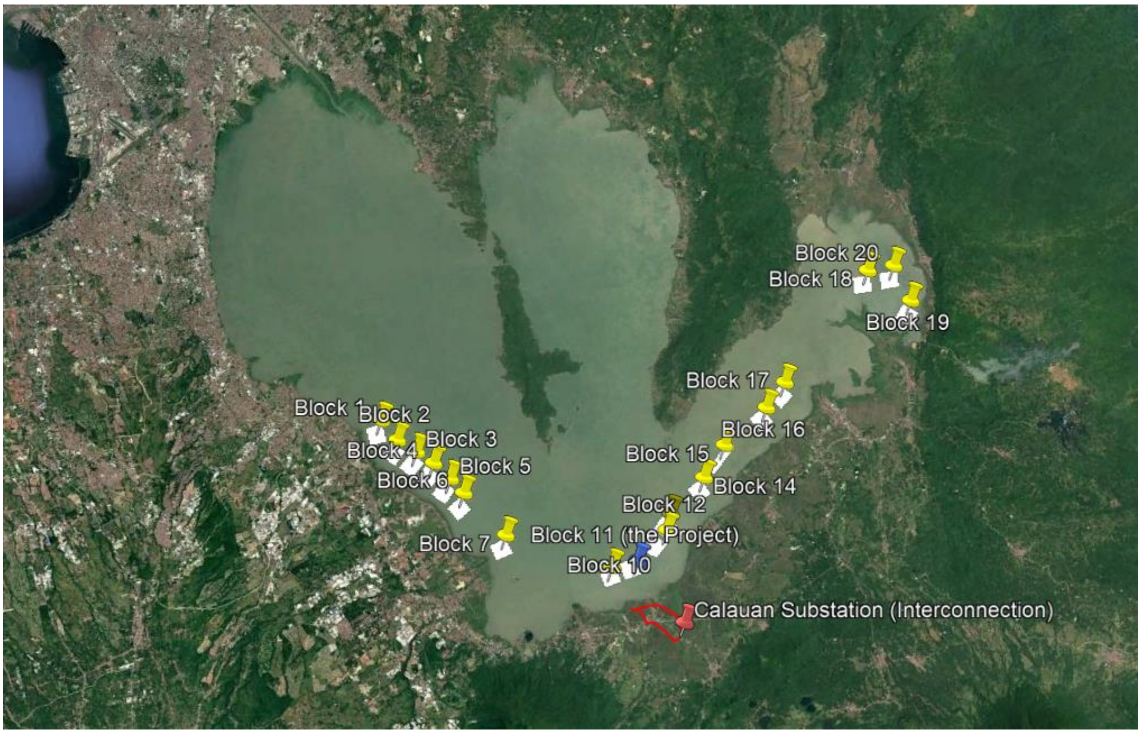
Aspects	Laguna Bay	Sagay	Magat
Project location	Luzon, Philippines	Western Visayas, Philippines	Luzon, Philippines
General site characteristics	The Project will be located on Laguna Lake which will be regulated by Laguna Lake Development Authority (LLDA) up to 4.5km from the shore. Under this assessment Laguna Bay Project is referred to Block 11 out of 20 blocks in total under the authority of LLDA.	The area is noted to be a fishpond located along the Himugaan river delta in Sagay, Negros Occidental.	The Project will be located inside the Magat dam reservoir (i.e., Magat Hydroelectric Power Plant) which is located along the Magat river.
Bathymetry and water level	In general, Laguna lake has high variation in water depth and due to its size. Based on the information provided, the water depth ranges from 1.1m to 4.6m and the wave height approximately ranges from 1.8m to 3.0m and be up to 8m for certain Blocks. Consequently, the characteristics of the Project site which affect the overall cost has been incorporated into our cost benchmarking.	The bathymetry and water levels at the Project site have not been assessed in this study. However, based on the site elevation profile available in the satellite imagery software, the Project has flat topography; therefore, we assume that the mounting structure can be installed without requiring grading. Significant wave variation is not expected since the Project will be located in the fishpond area.	Based on information available, the water depth at the Project reaches up to 30m with water level variations ranging from approximately 165 height above msl to 190 height above msl. The bathymetry characteristics could influence the selection of viable technology for the Project and consequently the overall costs.
Transmission and distribution system	Two 230kV overhead transmission line (OHL) routes and grid connecting points are planned for the Laguna Bay project including: • 11.5km OHL from the Project collector substation to NGCP Calamba substation; and • 4.7km OHL from another collector substation to	The overhead transmission line, approximately 11.2 km in length, will be routed from the project's substation to the Cadiz NGCP. No additional substation construction is required.	Given early stage of the Project, plan of transmission and distribution facility is yet to be confirmed. In this assessment, the Project is assumed to connect to the existing air-insulated substation of the Magat Hydroelectric Power Plant, with a total overhead line length of approximately 3km from the FPV system's HV transformer.

Aspects	Laguna Bay	Sagay	Magat
	MERALCO Calauan substation where Block 11 will be connected to. The total length of the overhead transmission line is approximately 16.2 km.		

Source: Client and Mott MacDonald

Figure 2.1 to Figure 2.3 present locations of the three Projects up to their grid interconnection point.

Figure 2.1: Laguna Project location



Source: Client and Mott MacDonald

Figure 2.2: Sagay Project location

Source: Client and Mott MacDonald

Figure 2.3: Magat Project location (with conceptual layout)

Source: Conceptual layout by Mott MacDonald for the purpose of the study

3 Key Technology pre-selection

3.1 Overview

The aim of technology pre-selection is to select key technology types and equipment models for use in energy yield assessments, cost benchmarking, and ultimately the LCOE assessment for the Projects.

This section discusses key considerations, such as advantages and disadvantages of commercially available technology options in the current solar PV market including PV modules, inverters, and mounting or floating structures. It also identifies suitable technology models for use in the assessments mentioned in the preceding paragraph.

At the time of writing this report, the Client has selected the central inverter type and stilt-mounted aquavoltaics mounting structure for Sagay and membrane-type floater for Magat. For the remaining technologies, we have conducted a preliminary technology identification exercise through reviewing publicly available sources and based on our experience with similar solar PV projects (i.e. floating solar plant and aquavoltaics) in the region.

It is worth noting that our pre-selection of specific key equipment models is primarily for the purpose of early-stage LCOE estimation for the Projects. This should not constraint the potential future selection of equipment models during the more advanced development stages of the Projects which may differ from those pre-selected here.

Table 3.1 summarises the status of technology's types selection for the Projects, indicating whether they were selected by Mott MacDonald or had already been selected by the Client.

Table 3.1: Status of technology's types selection of the representative projects

Key technology	Laguna Bay	Sagay	Magat
PV module	Selected by Mott MacDonald	Selected by Mott MacDonald	Selected by Mott MacDonald
Inverter	Selected by Mott MacDonald	Inverter type selected by the Client Inverter model selected by Mott MacDonald	Selected by Mott MacDonald
Mounting/ floating structure	Selected by Mott MacDonald (FPV – Pure float)	Selected by the Client (Stilt-mounted Aquavoltaics*)	Selected by the Client (FPV – Membrane type)

*Fixed mounted structures are not included in our technology pre-selection scope

3.2 PV Module

There are two main types of PV module technologies available in the current market - crystalline silicon and thin film. The former can be further categorised into monocrystalline silicon and polycrystalline technologies.

Key characteristics of monocrystalline silicon, polycrystalline silicon, and thin-film PV module technologies are discussed in Table 3.2.

Table 3.2: Summary of PV module technologies characteristics (monocrystalline silicon, and polycrystalline silicon, and thin-film)

PV module technology	Description
Monocrystalline silicon (Mono-c-Si)	Monocrystalline silicon cells are made of a single and continuous crystal of silicon which promotes more efficient electron movement within the cell and higher energy conversion efficiency relative to polycrystalline and thin-film. Mono-Si modules also offer a lower temperature coefficient compared with polycrystalline modules; therefore, their performance is less sensitive to changes in ambient and module temperatures. Historically, the high-quality silicon used in their production resulted in a higher price point compared to polycrystalline and thin-film modules. In recent years the mono-Si technology has become more cost competitive, and its overall yield benefit is generally expected to outweigh any higher cost in comparison to their counterparts.
Polycrystalline silicon (poly-c-Si or Multi-c-Si)	Polycrystalline modules are produced by melting multiple silicon fragments to create wafers. The manufacturing process of these is generally more cost-effective than that of monocrystalline silicon modules, primarily due to the reduced material waste involved. However, the construction of the polycrystalline modules result in less electron movement inside the cells and hence a slightly lower energy conversion efficiency in comparison to Mono-Si modules.
Thin-film	Thin-film modules are made by depositing a single or multiple layers of semiconductor material on a substrate, typically glass, plastic, or metal. The most common semiconductor materials used are cadmium telluride (CdTe), copper indium gallium selenide (CIGS), amorphous silicon, or gallium arsenide (GaAs). Thin-film modules have long strip-like cells arranged in parallel with the length of the module which can help mitigating electrical shading mismatch loss between cells when installed perpendicular to the source of shades. In addition, the modules also have a lower temperature loss coefficient. However, in terms of energy conversion, thin-film modules are generally less efficient than their crystalline counterpart. Given this, additional area utilisation is required to achieve an equivalent amount of energy compared with crystalline silicon modules.

Source: Mott MacDonald and public domain

In addition to the abovementioned PV module technologies, research and development have given rise to PV technologies with specific features that enhance their technical characteristics and performance. The improvements are generally achieved through the modification of the architectural structure of the PV cells. The technologies with such enhanced features which are commercially available in the global PV market are discussed in Table 3.3

Table 3.3: Summary of other innovative PV cell architectures and technology

PV module technology	Description
Passivated Emitter and Rear Cell (PERC)	PERC modules have been developed from the standard crystalline modules yielding an improvement in energy efficiency, which lowers the required area of the PV module deployment to achieve the same target capacity. Contributing to this increase in efficiency are the following architectural modifications of PV cells in the modules: ● PERC cell applies dielectric surface passivation together with the reduction of metal contact area to reduce loss from electron surface recombination. ● The dielectrically displaced rear metal reflector is included in the cell to increase the reflection from the rear surface for additional energy absorption. In addition, PERC modules can reduce installation cost in comparison to the standard crystalline modules considering a lower requirement on balance of system (BOS) components (e.g., electrical wires, connectors, racks, etc). Nevertheless, PERC technology may be susceptible to Light and elevated Temperature Induced Degradation (LeTID), resulting in performance loss after exposure to light at elevated temperatures. According to a study by Fraunhofer institute[1], the performance drop observed under LeTID tests ranges up to -3.6% for monocrystalline PERC and ranges up to -7.5% for polycrystalline PERC modules.
Half-cut cell	Half-cut or half-cell PV modules are a development from the traditional crystalline silicon PV modules with PV cells cut in half through a cleaving process. The technology delivers the following advantages: ● Lower power losses: As current output is reduced to half per cell, the resistive electrical loss is substantially reduced. ● Given the doubled substrings of half-cut technology, the power losses from partial shading of PV modules in an array can be expected to be reduced by up to 50%. The modules may gain benefit from the lower shading impact from half-cut technology only under the circumstances that the modules are installed in portrait orientation, due to the bypass diode configuration.
P-type and N-type cells	N-type solar PV modules are alternative which recently rise its market share due to its several advantages over the p-type PV module. The n-type PV module features a negatively doped bulk c-Si region (n-type) while the emitter layer is positively doped (p-type). N-type solar cells are made from a silicon wafer doped with phosphorus, which has one more electron than silicon making the cell negatively charged. On the other hand, P-type cells are doped with boron, which has one less electron than silicon making the cell positively charged. The presence of boron in p-type cells can lead to the formation of boron-oxygen (B-O) complexes as the boron interacts with oxygen in the air which causes a reduction the cell performance – i.e. light induced degradation (LID). According to the analysis by NREL[2], LID resulted from B-O complexes could lead to 1.5 to 2.5% performance loss of the module. N-type cells are resistant to LID due to the presence of phosphorus instead of boron within the silicon. Such characteristic also enables N-type cells to have longer lifespan compared to P-type, conventionally with an associated higher price of modules.
Dual-glass	Dual glass PV module is placed with a second layer of tempered glass on the rear side of the module which is traditionally placed with polymer material. According to a white paper by Trina Solar[3], the structure with a glass layer on both the front and rear sides increases durability under

[1] Information obtain from LETID – A comparison of test methods module level

[2] LID and LeTIDImpacts to PV Module Performance and System Economics (nrel.gov)

[3] INSTRUCTIONS FOR PREPARATION OF PAPERS (trinasolar.com)

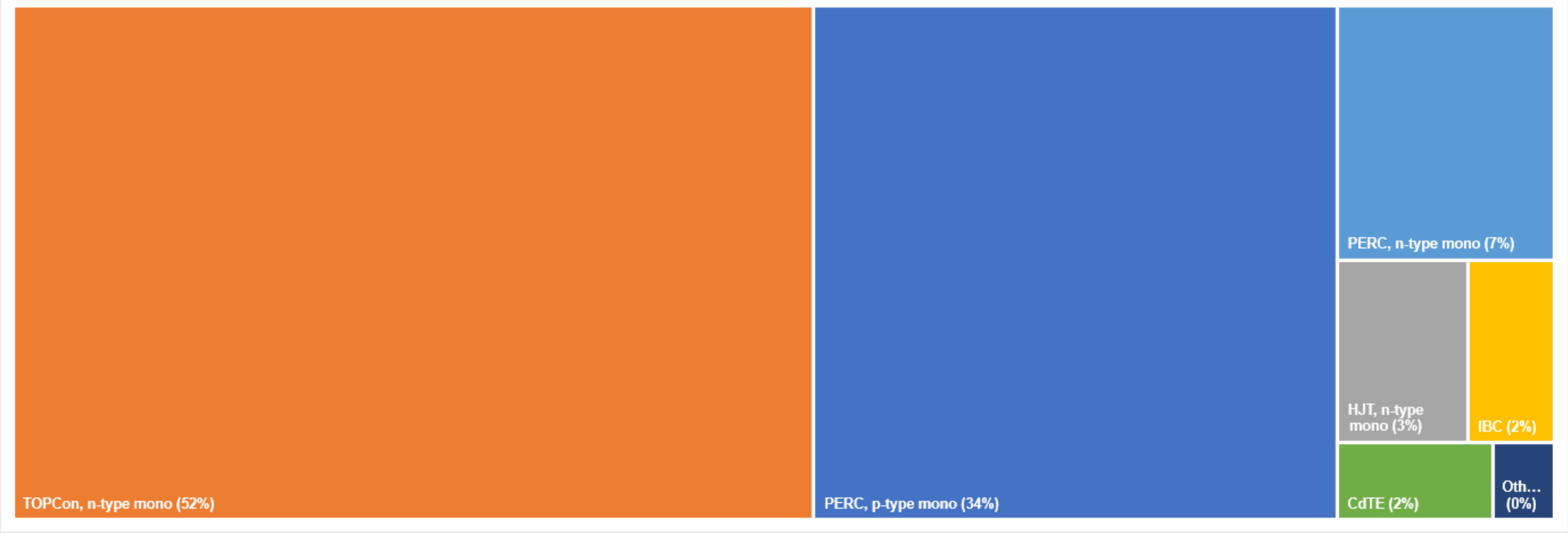
PV module technology	Description
	different stress conditions including heat, humidity, and mechanical loading, improves fire resistance, and reduces potential induced degradation (PID)[4].
Bifacial module	Bifacial modules are able to capture the sunlight incident on the rear side of the module, which is generally reflected from the ground, by using a transparent back sheet and rear electrode. The bifacial gain of the bifacial PV module can vary from less than 1% to over 5%, depending on the following key factors: • Ground surface properties (albedo) • PV modules rack design (e.g., PV modules clearance from ground, tilt angle, azimuth) • Spacing between PV arrays • Bifaciality of the PV modules Apart from application in fixed-tilt ground-mounted systems, bifacial modules can also be used with tracking systems, which helps amplify solar irradiation absorption on both sides of the module, hence increasing the bifacial gain.
Tunnel Oxide Passivated Contact (TOPCon)	TOPCon PV modules are a technology developed from PERC (p-type) and the Passivated emitter, rear totally- diffused (PERT, n-type) modules with slight differences in structure. The modifications include the addition of an ultra-thin silicon dioxide (SiO_2) layer at the base of the cell structure, working as the tunnel oxide layer; and the phosphorus-doped polycrystalline silicon layer as a back surface field. These modifications lower the recombination process of the electron-hole pair carriers generated from the PV cell's light absorption, which contributes to an improvement in module efficiency. However, these modules ordinarily have a relatively higher price due to higher requirement of silver materials for contacts of the PV cells in comparison to PERC PV modules. Given that this technology has emerged recently, it is important to note that there is a lack of available long-term track record of successful PV plants utilising TOPCon PV modules, and limited reliability tests in the international standards to confirm the reliability of this technology.
Heterojunction (HJT)	The HJT PV technology is manufactured based on a crystalline silicon PV cell encased with passivating amorphous thin-film silicon layers (a-Si:H) both at the front and rear side of the cells. With the passivated thin-film layers separating the highly recombinative-active contacts and the crystalline wafer, the HJT PV modules overcome the loss incurred from surface recombination of the carriers (electron-hole pair). This is a typical phenomenon experienced in the traditional crystalline silicon PV modules. The lower recombination loss yields a higher efficiency in comparison to the standard crystalline modules. Similar to TOPCon PV modules, the medium- to long-term track record of successful PV plants using HJT modules and reliability tests in the international standards are currently limited.

Source: Mott MacDonald and public domain

To further illustrate the maturity and competitiveness of each PV module technology in current market, the global annual shipment of 2023 by technology is illustrated in Figure 3.1 below.

[4] Potential Induced Degradation is a form of degradation caused by stray current accelerated by voltage levels and moisture.

Figure 3.1: Global annual solar PV supply by technology in 2023



Source: Spring 2024 Solar Industry Update dated May 14, 2024 Spring 2024 Solar Industry Update (nrel.gov)

We have considered monocrystalline silicon (Mono-c-Si) considering its higher energy conversion efficiency relative to polycrystalline and thin-film, noting that its overall yield benefit is generally expected to outweigh any higher cost in comparison to their counterparts.

For the specific PV module features, considering the recent PV module shipment (as presented in 3.1 and future market trend of PV module industry based on the public domain, TOPCon N-type PV modules technology has become more common due to its higher efficiency compared to the traditional and PERC PV modules and less complexity of its manufacturing process compared to HJT technology. The TOPCon N-type technology are being offered by several top-tier PV module manufacturers, where recent TOPCon N-Type PV modules normally include other PV module features such as half-cut technology, dual glass architecture, and bi-facial technology.

Although the use of bifacial modules with a floating solar plant may not significantly benefit from bifacial gain due to rear shading caused by the floating structure, low reflectivity of water surface, and limited height above water surface, the top-tier PV module manufacturers have commonly included this technology in their modules during recent years. In addition, the bifacial technology often utilises the dual-glass architecture which is more suitable for FPV and aquavoltaics applications.

Taking into consideration the above, we have selected **N-Type TOPCon half-cut with bifacial (dual-glass)** technology, with Jinko Solar (i.e., 66HL4M-BDV) as the representative PV module model for application in subsequent assessments for the Projects.

For the Magat Project, with the envisaged applications in membrane-type floating system, we understand that the PV modules need modifications to position the junction boxes on the front side (instead of the rear side for a typical PV module). This adjustment will expose the junction boxes more extensively to environmental conditions (e.g. more sunlight and humidity) and thus require them to have improved IP ratings. The envisaged PV module would be expected to undergo additional testing (e.g., UV test, thermal cycling, and damp heat test etc.) to ensure the durability / longevity of the components required compared to other solar PV applications.

3.3 Inverter

The most commonly used inverter technologies in large scale grid connected PV systems are central inverters and string inverters. Central inverters are connected to string combiner boxes combining strings of PV modules. While string inverters have strings of modules connected directly to the inverter. Comparative advantages and disadvantages of each inverter type are discussed in Table 3.4.

Table 3.4: Summary of inverter types for utility scale projects (central and inverters)

Inverter type	Description
Central inverter	Central inverters can have large power ratings. Therefore, a lower quantity of inverters is required compared with PV plants with string inverters, given the same AC plant capacity. This results in the following advantages: • For large-scale floating solar PV plants with a simple and homogeneous design on stagnant water surface which do not benefit significantly from multiple Maximum Power Point Tracking (MPPT) inputs, central inverters may offer a more cost-effective option for inverter selection. • Given their centralised configuration, central inverters’ output regulation to meet grid requirements (e.g., grid curtailment, power quality control, reactive power compensation, power factor control) is relatively less complex. • Central inverters are typically equipped with dedicated cooling systems which may allow for more effective management against saline ingress, in case of installation in saline atmospheric conditions. Nevertheless, when considering central inverters for plant designs, there are a few other considerations that should be taken into account, mainly due to their large capacity and physical size: • Considering that the failure of a single central inverter results in a great amount of energy loss compared to the string inverter, there is a significant risk of losing energy generation in case of failures. • Unlike string inverters, central inverters do not have the functionality (by default) to monitor output at the PV string level. During the operational phase, this may lead to difficulties to identify low-performing strings. • Some central inverter models may require an additional temperature control system to maintain the effective operating temperature. Additional auxiliary consumption to support such temperature control system should be accounted for in the PV system design. It is noted that the temperature control system of the inverter depends on the environmental condition at the project site, e.g., site ambient temperature, and the built-in temperature control system within the inverter. Such heating, ventilation, and air conditioning (HVAC) systems enable the inverters and associated instrumentation to operate in optimal conditions and reduce the ingress of dust, humidity and other external factors affecting inverters performance and resilience.

Inverter type	Description
	Per unit, reparation and or replacement of central inverters can be more expensive than string inverters. The repair work can be more complex as it requires special equipment and extensive labour for transportation and installation.
String inverter	The main features of string inverters are different from central inverters. They may be selected over central inverters under certain plant operating conditions given their benefits as summarised below: • A configuration with string inverters allows for more flexible tracking of MPP of the PV arrays with different designs and configurations. This helps optimise the generation from PV modules connected to each MPPT unit. • The use of string inverters allows a more granular performance monitoring of PV arrays in comparison to central inverters, assuming no separate string monitoring is installed. With string inverters, underperforming PV strings can be more easily detected. • A failure of a string inverter has a relatively lower impact on the overall PV plant generation due to its small power rating. However, there are trade-offs for the advantages discussed above considering their smaller power ratings: • It requires more units of string inverters to be deployed to achieve the same plant AC capacity than projects with central inverters. Therefore, more time is generally required for routine maintenance of all units in a PV plant. • Regulation of inverter output to meet grid interface requirements (e.g. grid curtailment, reactive power compensation, power factor control) is similarly more complex considering the number of components and string inverters do not offer relevant capabilities, which instead need to be supplemented separately where required at the plant substation(s). String inverters rely on natural cooling systems which, in case of application in saline atmospheric conditions, may introduce more challenges in saline ingress protection.

Source: Mott MacDonald and public domain

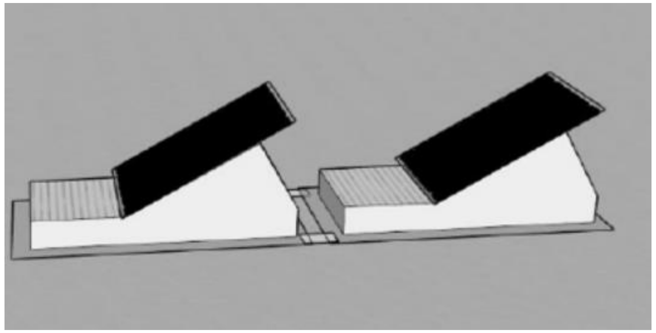
Technical benefits of central and string inverters without consideration of project specific conditions and requirements could not explicitly determine the more suitable technology option for floating solar PV applications. A techno-economic viability study should be conducted to comprehensively compare efficiency and cost-benefit aspects of each inverter type. In this assessment, as agreed with the Client, for the purpose of the subsequent EYA and LCOE assessment **central inverter** has been selected according to its stronger track record in FPV applications in the region. Regarding the manufacturer and model, we have considered Sungrow SG4400UD-MV as the representative central inverter model for utilisation in other assessments for all Projects.

3.4 Floating platform

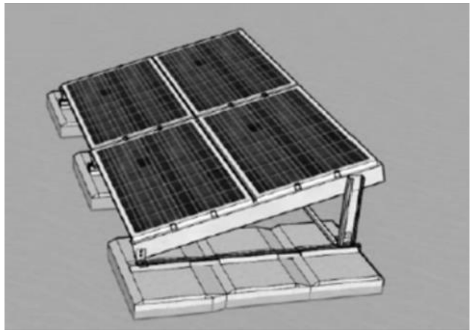
The main purpose of floating platform is to provide installation support and buoyancy for the PV modules, inverters (except when these are installed on the shore) and other balance of plant (BoP) components over the water surface. Floating platform also provides required access and walkways for the operation and maintenance (O&M) activities of plant equipment installed on the floater.

The three types of FPV structures as per the categorisation by DNVGL-RP-0584 are presented in Figure 3.2.

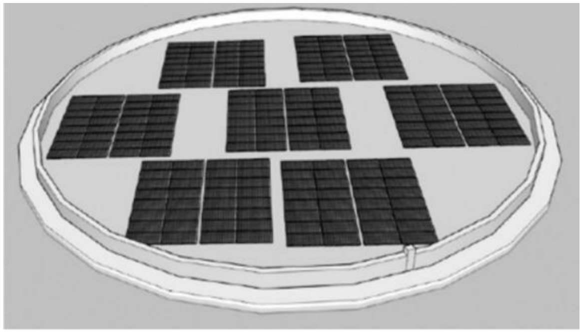
Figure 3.2: Classification of FPV structures as per the categorisation by DNVGL-RP-0584



Pure floats



Modular rafts



Membranes

Source: MDPI Design and Analysis of a Floating Photovoltaic System for Offshore Installation: The Case Study of Lampedusa

Summary of different types of typical floating platform and floating structures (including anchoring systems, and mooring systems) are presented in Table 3.5.

Table 3.5: Summary of floating platform and floating structure characteristics for utility scale projects

Items	Description
Floating platforms	
Pure floats	Pure-float configuration has special designed buoyant structures that can directly support solar PV panels and is considered to be the most common type of floating platform. The advantages of pure floats type are as follow: • Pure-float type requires fewer metal parts which could reduce the corrosion risk. • Pure-float type is easy to assemble and install. The installation also benefits from its typically scalable system which does not required major changes in the design – e.g. in case more installation/expansion required. • The platform can adapt to wave motion and as a result reduce stress on the structures. However, there are some disadvantages that should be taken into account: • The proximity of the modules to water could limit air circulation and diminish the cooling effects from evaporation. This could also lead to a high-humidity environment for both PV modules and cables. • The constant movement of the platform may also induce stress and fatigue on joints and connectors.
Modular rafts **(floats with metal structure)**	Modular rafts employ metal structures to mount solar panels on floating pontoons which serve only to provide buoyancy. This type of structure requires relatively lower quantity of supporting floats and does not usually need a specially designed float system, and hence more preferable in certain cases given that the metal structure is typically easier to obtain than pure floats. The metal structure is typically coated with special anti-corrosion coating (e.g., zinc-aluminium-magnesium alloy steel). The advantages of modular rafts type are as follow:

Items	Description
	• The simplicity of the concept and the metal structure could be easily obtained locally in certain regions. • Its design could minimise the variability of wave movement between PV modules, reducing wear and tear on module connection components and wires. However, there are some disadvantages to float systems with metal frames as follow: • The concentration of stress from the wave at certain points due to the increased rigidity of the structures. • Although the general concept of this structure type is simple, the structures are often more challenging to assemble. In addition, access for maintenance could be difficult for certain types of float design.
Membrane type (Superficial flexible Design)	Modules are attached to a reinforced membrane (i.e., polymer) supported by rigid structures (i.e. tubular rings) which also provides buoyancy support. The advantages of membrane type are as follow: • The design is conceptually simple, and easy for installation and maintenance. • As the modules have direct contact with the membrane which allows for efficient heat transfer between the modules and water, the design promotes heat dissipation and hence increased module performance[5]. However, there are some disadvantages to the membrane type as follow: • From available documentation, the PV modules installation are limited to horizontal design (i.e., 0-degree tilt), which potentially limit irradiance transposition gain as the PV modules might not be installed at the optimal tilt angle. • The 0-degree tilt configuration will potentially result in higher soling loss compared to the tilted PV modules configuration. Apart from the technical perspective, we highlight that membrane type floater has limited track record (especially for the utility-scale project) compared to other types of floating platforms - one example project is Banja floating solar plant on Statkraft's Banja hydropower plant in Albania with the DC capacity of 2MWp.
Anchoring system	
Self-weighted anchors	These anchors resist movement by their own weight and friction with the ground. They are usually the preferred option for bottom anchoring because their minimal maintenance requirement and simple installation provides a cost effective solution; however, they are unsuitable in soft or accreting seabed due to the complex mooring line interactions that occur once buried.
Piled anchors	These anchors are steel tubular piles which are driven, bored or helically screwed into the soil. Piled anchors are suitable for soft or accreting seabed; however, they require a more expensive installation, especially when adopted for bottom anchoring in deep waters. Floating structures can be moored to piled anchors by either vertical sliding pile guides or mooring lines. Helical anchors with mooring lines are the preferred option for bank anchoring due to their high lateral resistance and more affordable land installation. Alternative pile types, e.g. bored cast in-situ or driven precast, might be appropriate if the equipment for these techniques is available locally but they would need to be suitable for the installation location. In particularly deep waters with high horizontal loadings, a pile group structure, such as mooring dolphins, should be adopted. This is because the adoption of a single monopile would require a size that is impractical for transport, fabrication and installation at the site.
While not classified as a specific type of anchoring system, there are generally two possible locations for the installation of anchoring systems, which include the following: • Bottom anchoring: Anchoring to the bottom of the pond which is suitable for any water depth, however, it has to be noted that raft movements will be significant at large water depths with large water level variations. This anchoring system can be achieved with self-weight or piled solutions; and	

[5] Oceansun.no/benefits/

Items	Description
• Bank anchoring: Anchoring placed on the bank of the body of water which is suitable for rafts located close to shore, usually in shallow basins and ponds with limited water level variation. Due to easy access, this is the most cost-effective anchoring solution to install and maintain. Bank anchoring allows rafts to be moored significantly closer to water body embankments, which can reduce power cable lengths and increase raft layout space.	
Mooring systems	
Fixed length mooring lines	These are mooring lines made of high-tension materials attached directly to a floating structure and anchoring system. They firmly hold floating structures under tension at high water levels while allowing movement at reduced water depths, creating slack lines on one side of the platform. The simplicity of the design allows for cheap maintenance and construction costs; but can force a floating structure to submerge or fail the anchor if the water depths exceed the designed maximum. To avoid tangling of the slack mooring lines, lengths of chains are used at both ends of the line which prevent the lines floating at the surface and lay along the bed at the bottom. The central length of the mooring line would usually be an artificial fibre rope. A significant limitation of fixed length mooring lines is in locations of varying bed levels, the variation in mooring line angles lead to twisting of the floating platform and large variations in mooring line tension at low water levels.
Weighted mooring lines	These are mooring lines of similar construction to the fixed mooring lines discussed above; however, the lines are kept in tension by submerged weighted blocks hung from the rafts/pontoons or attached to the centre of the mooring line. This weighted design is more complex than a fixed option, therefore there are increased associated maintenance and construction costs; however, the excess length allows for a much larger designed maximum water depth and mitigates the effect of bed level variations.
Pile guides	These mooring systems consist of small steel frames attached to the floating structure and wrap around a piled anchor. Rollers or guides allow the pile guide to slide up and down the pile so as the water level changes the floating structure changes elevation. Pile guides prevent horizontal movement of a structure.

Source: Mott MacDonald and public domain

For the floating platform for Laguna Bay, we have selected the pure float type considering that it is the most common type of floating platform and its strongest track record compared to other types. In addition, the advantage of simple assembly and installation and the ability of system scaling could be beneficial to the GWp-scale of the Project. Furthermore, the Project location is considered to be in the windy area where dual-pitch PV array design is typically adopted mainly to reduce the wind drag. According to the public domain, only manufacturers of pure floats type offer the dual-pitch design. Therefore, we have selected the **pure float structure** with **Sungrow SGF-TS30** as the representative floaters model for utilisation in the subsequent assessments.

In addition, as discussed with the Client regarding the wave conditions at Laguna Bay Project, wavebreaker should be installed in order to reduce the impact of wave to the FPV system. The cost associated with the wavebreaker has been incorporated into our cost benchmarking discussed in sub-section 5.2.1.3.

For Sagay, the Client has already selected the mounting structure to be a **stilt-mounted structure** with south-facing azimuth. This type of mounting structure comprises of piles and racks. Compared to floating system, the mounting structure of Sagay is not expected to experience dynamic movement from the water, allowing less complexity. However, the stilt-mounted structure on water would still require additional design, installation, and operational requirements (e.g., elevated MV stations, draining water from the installation area, use of high-powered equipment and specialist labour).

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For Magat, the Client has selected the **membrane type floater** from Ocean Sun to be utilised for the Project. We note that a track record of this float technology in utility-scale applications is limited compared to other type of floaters (i.e., at the time of writing this report, Ocean Sun project track record with the highest installed capacity is only 2MWp whereas the expected capacity of the Project is 126.3MWp). Given the Project's scale significantly exceeds the manufacturer's track record, if further development of the Project is envisaged, the manufacturer should provide a risk mitigation plan regarding the production rate to ensure the timely supply of equipment as outlined in the supply agreement. Similar to dual-pitch arrangement, the design of membrane type in which PV modules are horizontally installed is beneficial for reducing the wind drag on the modules.

For Laguna and Magat, the design of anchoring and mooring systems depends on site-specific conditions (e.g., water level variation, bathymetry, soil conditions, environmental impact, etc.). Detailed studies will be required to assess the specific requirements of these components, as floating platform suppliers typically recommend the appropriate anchoring and mooring types for their designs. The selection of mooring and anchoring systems is not crucial for the energy yield assessment in subsequent sections; therefore, this aspect has not been focused this section.

3.5 Conclusion

The selection of technology has been proposed and agreed with the Client during the technical discussions preceeding issuance of this report. The considered key equipment technology and equipment model for our subsequent assessments are summarised in Table 3.6.

Table 3.6: Pre-selected key equipment

Key technology	Laguna Bay	Sagay	Magat
PV module	n-type TOPCON half-cut with bifacial (dual glass) Jinko Solar: JKM650N-66HL4M-BDV (selected by Mott MacDonald)	n-type TOPCON half-cut with bifacial (dual glass) Jinko Solar: JKM650N-66HL4M-BDV (selected by Mott MacDonald)	n-type TOPCON half-cut with bifacial (dual glass) Jinko Solar: JKM650N-66HL4M-BDV (selected by Mott MacDonald)
Inverter	Central inverter Sungrow: SG4400UD-MV (selected by Mott MacDonald)	Central inverter (selected by the Client) Sungrow: SG4400UD-MV (selected by Mott MacDonald)	Central inverter Sungrow: SG4400UD-MV (selected by Mott MacDonald)
Mounting structure	Fixed tilt (pure float type) with dual-pitch arrangement Sungrow: SGF-TS30 (selected by Mott MacDonald)	Stilt-mounted – the model to be confirmed by the Client (selected by the Client)	Horizontal orientation (membrane type) OceanSun: OS-75 (selected by the Client)

Source: The Client, Mott MacDonald

4 Energy Yield Analysis results

4.1 Overview

In this section, we have undertaken the energy yield assessment (**EYA**) to provide an estimation of the expected energy production and plant performance ratio (**PR**) of the Projects. The EYA result is used as part of Levelized Cost of Electricity (**LCOE**) calculation where the estimated LCOE outcome is expected to further support the Client's revenue scheme discussions (e.g., Feed-in Tariff, etc.) with relevant authorities.

The EYA for the Projects has been carried out based on documentation received from the Client and email correspondence up to 16 October 2024, using our in-house yield models and simulation through PVsyst software (version 7.4.8), based on following steps:

1. **Solar resource assessment**
   The representative global horizontal irradiance and ambient temperature were retrieved from Solargis Prospect. Further details are provided in Section 4.2.
2. **Plant Configuration**
   Plant configurations, including array orientation, array-string configuration, inter-row spacing are considered and proposed based on our experiences, unless previously selected by the Client. While specifically for tilt angle, an analysis was conducted to identify the angle offering the highest specific yield, incorporating solar resource assessment, technical assumptions, and key technology pre-selection.
3. **Energy yield assessment**
   Utilising the results and assumptions from Steps 1 and 2, EYA has been performed. The results, as presented in Sections 4.5 to 4.8, includes the system losses, PR, an uncertainty analysis, and expected annual energy production over the envisaged Projects lifetime of 20 years, including the P50, P75, P90, and P99 values.
4. **Sensitivity analysis**
   Given that water-cooling effect on PV system performance is largely subject to the site location, specific site surrounding and meteorological condition and floating technology used, sensitivity analysis has been conducted by varying the thermal constant loss factor (Uc) considering different types of mounting structure to identify potential upside and downside of the energy generation, considering the expected range of applicable Uc.

4.2 Solar resource assessment (SRA)

Irradiance can be measured by weather stations using a pyranometer or derived from satellite images and is usually recorded as Global Horizontal Irradiance ("**GHI**") (the amount of sunlight that falls on a $1m^2$ horizontal area). Mott MacDonald's solar resource assessment in this section does not take into account any change in the climatic and atmospheric conditions in the future (e.g., from climate change or variations in air quality).

4.2.1 Available meteorological data

To select the most representative irradiance data source for any solar PV plant, Mott MacDonald typically compares several different sources of irradiation data. Specifically for projects in the Philippines, we evaluate four sources as follows:

- Meteonorm 8.0 interpolated database;
- NASA POWER GIS satellite-derived database;
- Solargis Prospect satellite-derived database; and
- Philippine Atmospheric, Geophysical and Astronomical Services Administration (PAGASA).

The characteristics of these data sources are summarised in Table 4.1.

Table 4.1: Solar resource database characteristics

Database	Meteonorm 8.0	NASA POWER GIS	Solargis Prospect	PAGASA
Description	Meteonorm 8.0 applies interpolation between weather stations, and a limited weighting on satellite imagery data to estimate irradiance parameters with a low density of available ground-based data.	NASA Power GIS provides averaged daily time series irradiation and other meteorological data derived from satellite images, at a 0.5° grid resolution and interpolated using NASA data interpolation tools.	Solargis Prospect is a high-resolution source of solar resource information. The data is calculated using in-house developed algorithms that process satellite imagery, atmospheric data, and geographical inputs. The accuracy of data particularly depends on the condition of atmospheric aerosols and the availability of high-quality ground measurements around the site.	PAGASA offers terrestrial meteorological measurements from 54 weather stations, 18 of which providing solar irradiation records, throughout the Philippines. The quality, quantity and availability of irradiance data varies depending on the specific station.
Data type	Satellite and satellite and ground-combined	Satellite-based	Satellite-based	Terrestrial data
Spatial resolution/ Distance	8km x 8km or specific distance of station from site	55km x 55km spatial resolution	250m spatial resolution	Distances from the stations with over 10 years data to the Projects range from over 55 to 480km.

Database	Meteonorm 8.0	NASA POWER GIS	Solargis Prospect	PAGASA
Available period	1996 – 2015	1981 – present	2007 – 2023	Currently, 2 out of 18 stations offers period over 10 years. Metro Manila: 2013 – 2024 ISU Isabela: 2013 – 2023

Source: PAGASA, Meteonorm, NASA POWE GIS and Solargis Prospect

Of the aforementioned irradiance data sources, PAGASA Meteonorm and NASA POWER GIS are also only used as references for comparison, but are not selected provided the following rationale:

- **PAGASA:** We note that irradiance data retrieved from terrestrial stations are potentially more accurate data and, per best practice, more preferrable compared to satellite and ground interpolated data. This is however subject to the following aspects of the data source are achieved:
  - Availability of up-to-date long-term data;
  - Located within reasonable distance to the Project site;
  - Similar of environmental conditions to the Project site (e.g., atmospheric conditions, terrain, etc.); and
  - Installation, operation and maintenance scheme (e.g., siting, cleaning, and recalibration, etc.)
  - Type of instrumentation and data logging;

  Mott MacDonald typically expects at least 10 continuous years of measurement to sufficiently account for inter-annual variability of solar resources. According to clarification from PAGASA, only 2 out of 18 solar irradiation stations have over 10 years data period: Metro Manila station with available data from 2013 to 2024 and ISU Isabela station with available data from 2013 to 2023. PAGASA stations, located on land expected to contain dissimilarity of microclimate conditions (e.g., pollution, humidity, elevation, etc.) to the Projects which are on the water bodies. In addition, we would also expect the terrestrial stations which have not been validated to be located in close proximity (i.e., 25km radius), to record similar irradiance pattern to the Projects. The distance from Metro Manila station to the farthest area of Laguna Bay is 55km and even farther for Sagay and Magat. On the other hand, the distance from ISU Isabela station to Magat is 26km (with a significant difference in elevation) and the distances from this station are even farther from Laguna Bay and Magat. Following the aforementioned reasons, ground-measured data from PAGASA have not been selected as representative data source for the Projects.

- **Meteonorm:** Although Meteonorm can provide an adequate interpolation procedure in case that a high density of reference ground-measurement stations relative to the complexity of surrounding topography is available within reasonable distance, this is not the case for the Projects locations. In addition, we noted that the spatial resolution that can be achieved is 8km x 8km which is still considered low compared to Solargis Prospect. At the moment, we are not aware of any publicly available validation study of Meteonorm's satellite-derived database against terrestrial ground measurement data in Philippines and hence the relevant uncertainty of Meteonorm sources for this Portfolio cannot be quantified.
- **NASA:** The NASA website provides NASA POWER GIS, a geographical information system designed to contribute a high-resolution with an irradiance dataset of 0.5° global grid (55km x 55km). We note this resolution is significantly lower than other referenced sources, and is insufficient to capture complex microclimatic effects, which can lead to significant spatial irradiance differences in some areas. The time series of daily surface irradiance data may include multiple data sources because of continuous upgrades of the model used; accordingly, NASA POWER GIS is not

recommended for use in assessing meteorological trends, given these may instead reflect a source data change. Uncertainty levels related to these constraints are not quantified and may potentially affect the accuracy of EYA.

From the above reasons, the solar resource from **Solargis Prospect** – long-term average satellite-derived solar resource from the period of 2007 to 2023 and 1994 to 2023 for irradiation and ambient temperature, respectively, at the Project site locations has been selected as the representative solar resource inputs to the EYA.

4.2.2 Global Horizontal Irradiation (GHI) and ambient temperature

The representative long-term GHI and ambient temperature used for the EYA are retrieved from the Solargis Prospect monthly meteorological database (satellite-derived) which are based on data recorded over the period of 2007 to 2023.

The monthly GHI and the ambient temperature for each location is presented in Table 4.2

Table 4.2: GHI and ambient temperature for the Projects

	Laguna Bay		Sagay		Magat	
Month	GHI (kWh/m^2-yr)	Ambient Temp. (°C)	GHI (kWh/m^2-yr)	Ambient Temp. (°C)	GHI (kWh/m^2-yr)	Ambient Temp. (°C)
January	124.7	25.0	121.8	25.4	115.4	21.7
February	138.9	25.3	139.0	25.5	129.3	22.3
March	181.6	26.4	186.5	26.2	173.7	23.8
April	189.4	27.8	194.9	27.2	187.2	25.8
May	182.9	28.4	187.1	27.8	202.3	26.9
June	158.6	27.8	160.2	27.5	193.3	27.0
July	144.0	27.1	153.5	27.2	179.4	26.4
August	140.9	27.1	164.0	27.3	165.0	26.3
September	138.6	27.0	152.0	27.2	162.0	25.8
October	135.4	26.9	154.7	26.8	135.8	24.9
November	121.5	26.5	143.0	26.6	117.2	24.1
December	111.9	25.7	130.4	26.0	102.0	22.5
Year (total / average)	**1,768.5**	**26.8**	**1,887.1**	**26.7**	**1,862.6**	**24.8**

Source: Solargis Prospect

As a separate recommendation, in case of the revisitation of EYA at the more advanced project stage, for a more accurate representative GHI at the Project sites the Client may wish to consider installing an onsite weather station and initiating a GHI measurement campaign. The short-term onsite solar resource measurement, once recorded for a minimum one year, can then be used to perform site-specific adjustment with long-term satellite-derived irradiance. The onsite weather station can be equipped with irradiance and temperature sensors.

4.2.3 Global Inclined Irradiation (GII)

An estimation of the transposition effect at the Projects has been performed in order to provide expected irradiation uplift resulting from different module orientations based on the PV layout. In this instance, Laguna Bay has been configured at a tilt angle of 5° and azimuths of -102° and 78° based on the representative block (Block 11) as agreed with the Client[6] with the dome configuration, Sagay has been configured at a tilt angle of 8° with south-facing azimuth, and Magat has been configured at a 0-degree tilt angle. Note that the applied tilt for Laguna Bay and Sagay is based on the tilt angle analysis result that will be further explained in Section 4.4.

The result of percentage uplifts and GII, obtained by PVsyst (version 7.4.8) using Perez transposition model for the Projects is presented in Table 4.3.

Table 4.3: GII and uplift for all locations

	Laguna Bay		Sagay		Magat	
Month	**GII (kWh/m^2-yr)**	**Uplift**	**GII (kWh/m^2-yr)**	**Uplift**	**GII (kWh/m^2-yr)**	**Uplift**
January	124.4	-0.3%	129.5	6.3%	115.2	-0.1%
February	138.8	-0.1%	145.3	4.5%	129.2	-0.1%
March	181.5	-0.0%	190.6	2.2%	173.7	-0.0%
April	189.4	-0.0%	193.3	-0.8%	187.2	-0.0%
May	182.8	-0.1%	180.6	-3.5%	202.1	-0.1%
June	158.3	-0.2%	153.2	-4.4%	193.1	-0.1%
July	143.7	-0.2%	147.7	-3.7%	179.3	-0.1%
August	140.8	-0.1%	161.0	-1.9%	164.9	-0.0%
September	138.3	-0.2%	153.1	0.7%	161.9	-0.0%
October	135.3	-0.1%	160.7	3.9%	135.7	-0.1%
November	121.5	0.0%	153.0	7.0%	117.1	-0.1%
December	111.7	-0.2%	140.4	7.7%	101.9	-0.1%
Year (total / average)	**1,766.5**	**-0.1%**	**1,908.4**	**1.1%**	**1,861.4**	**-0.1%**

Source: Solargis Prospect and PVsyst

[6] As instructed by the Client, Block 11 has been selected as representative block under this assessment given its lowest GHI among blocks, to represent all other FPV projects in Laguna Bay.

4.3 Key assumptions applied to the EYA

Certain assumptions have been made to quantify system losses based on our in-house database of similar scale projects in the region and information available in public domain where applicable.

The key missing information is highlighted as follows:

- Test reports of the PV module;
  - Incidence Angel Modifier (IAM) test report;
  - Low irradiance performance test report;
  - Light induced degradation test report;
  - Flash test results;
- Test reports of the inverter;
  - MPPT[7] efficiency test;
- Load lists and load schedule for auxiliary consumptions;
- Transformer specifications (load/no load losses);

  (While the technical specification for the transformer is not available at this stage, we have assumed load and no-load losses based on the assumption that the MV and HV transformers to be selected for Projects will be optimally sized and designed, following appropriate design practice)
- DC & AC wiring configuration and cable specifications (except the AC wiring details within each FPV island of Laguna Bay which is available); and
- Revenue meter locations;

In the absence of the abovementioned information, key assumptions have been made based on our experience with regards to losses and relevant parameters for the Projects as outlined in Table 4.4.

Table 4.4: Key assumptions for the EYA

Assumptions / Losses	Conditions / % Annual Losses
Incidence angle loss	An assumption of incidence angle loss is based on the incidence angle modifier (IAM) profile of anti-reflection (AR) coating modules using Fresnel's laws in PVsyst simulation.
Soiling loss	-1.0% under the assumption that the appropriate PV module cleaning scheme will be conducted during dry season.
Low-irradiance performance loss	Default R-series values defined by PVsyst.
Power tolerance loss	+0.8% (gain) (1/4th of the specified power tolerance in the datasheet).

[7] Maximum power point tracking

Assumptions / Losses	Conditions / % Annual Losses
Light-Induced degradation (LID)	-0.6% based on the module supplier's guaranteed value from the datasheet (difference between first-year module degradation and linear power degradation guarantees).
Mismatch loss	-0.6% (4/5th of the % power tolerance).
Dynamic MPPT loss	-0.5% for central inverter type.
DC wiring loss	-1.5% of DC wiring loss under STC for central inverter type based on our standard assumption for a well-designed wiring scheme from our project experience in the region.
AC wiring loss	-1.0% of AC wiring loss under STC for central inverter type based on our standard assumption for a well-designed wiring scheme from our project experience in the region.
MV transformer loss	-1.0% based on our internal benchmark and past project experiences.
HV transformer loss	-0.5% based on our internal benchmark and past project experiences.
Revenue meter location	Assumed to be located at the grid interconnection point – i.e. Calamba substation for Laguna Bay and NGCP Cadiz for Sagay. For Magat, based on discussion with the Client, the revenue meter is assumed to be at the existing air insulated substation of Magat hydroelectrical power plant.
Transmission line loss	Transmission line is assumed to be -0.2% for Laguna Bay and Sagay Projects. While the transmission line loss for Magat is assumed to be negligible given its revenue meter location is expected to be at the existing air insulated substation of Magat hydroelectrical power plant which is in close proximity to the Project HV switchyard.
Auxiliary power consumption (daytime) loss	-0.5% for central inverter type
Plant unavailability loss	-1.0% based on Mott MacDonald's experience of PV plants with adequate operation and maintenance and no significant/atypical grid downtime.
Annual power linear degradation	-0.5%/year based on discussion with the Client (further discussed in Section 4.8).
Power factor at interconnection point	1.0 assuming the power factor requirement under normal operating condition.
PV module height above water surface	**Laguna Bay:** 0.2m – determined based on our prior experience with FPV projects. **Sagay:** 0.5m – assumed to the design array height above maximum water level based on our prior experience with stilt-mounted projects on fishpond and flood prone area. **Magat:** 0.05m – assumed to account thickness of the floater's material.
String configuration	I-shape configuration (Figure 4.1)
Assumptions related to bifacial simulation[8]	
Ground albedo	0.07 referencing the research paper[9] – suggested that the albedo of a water surface tends to be lower than typical assumption of 0.2 for ground surface.

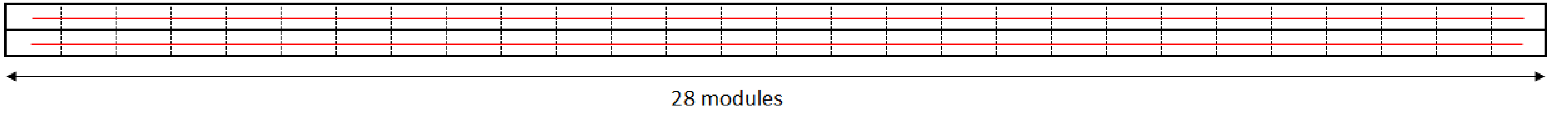
[8] We note that despite bifacial PV module selected for the Magat Project, the bifacial gain for the Project is expected and assumed to be negligible considering the PV modules will be installed horizontally and in contact with the membrane floater such that no significant irradiance may reach the PV module rear side.

[9] Liu, H., et al. Field experience and performance analysis of floating PV technologies in the tropics. Progress in Photovoltaics: Research and Application, 26(12), Pages 957-967

Assumptions / Losses	Conditions / % Annual Losses
Near shading factor at rear side of PV module	Laguna Bay: 40.0% determined based on the ratio between the coverage area of a floating platform and the rear side of the PV module referencing from our prior experience with similar FPV projects. Sagay: 5.0% of default settings as recommended by PVsyst has been applied for the typical rack type mounting structure
Mismatch loss factor at rear side	-10.0% of default settings as recommended by PVsyst.
Bi-faciality factor of selected PV module	0.8 based on the value specified in the PV module datasheet.

Source: Information provided by the Client and Solargis

Figure 4.1: I-shape string configuration – Example for Laguna Bay (dome configuration using landscape module arrangement with 1 row of modules per side)



Source: Mott MacDonald

We note that the red straight line illustrates the wiring between PV modules in a PV string for Laguna Bay. While the PV arrays in Sagay have a portrait orientation and four rows of modules instead of two rows, we assume that the wiring remains I-shape, similar to Laguna Bay. For Magat, I-shape wiring for the corresponding 26-module strings in portrait is assumed.

4.4 Plant configuration

In this section, plant configurations, including array orientation, array-string configuration, inter-row spacing are considered and proposed based on our experiences. The objective of this exercise is to establish reasonable assumptions for the key plant configuration parameters required for the EYA, where relevant supplementing information has not been made available at this stage.

Specifically for tilt angle, an analysis was conducted to identify the angle offering the highest specific yield, incorporating solar resource assessment, technical assumptions, and key technology pre-selection. The tilt angle analysis is discussed in Section 4.4.1.

Table 4.5 outlines parameters utilised as part of the abovementioned EYA and tilt analysis.

Table 4.5: Plant technical parameters utilized in EYA

Key parameter	Value	Description
Laguna Bay (Floating Solar PV – Pure float type)		
Coordinates	14.2118°, 121.2739°	Mott MacDonald has been instructed by the Client to conduct the simulation of the Laguna Bay Project for a single representative block to represent all other FPV blocks envisaged for development at the lake. As agreed with the Client Block 11 has been designated as the representative block for our assessment. We have developed a preliminary layout and plant configurations based on the target AC capacity and coordinates indicating the Project's representative block boundary provided by the Client. The DC capacity has been derived from a DC/AC ratio of 1.3 based on the typical DC/AC ratio range of 1.2 – 1.4 observed from our previous project experiences in this region. The inter-row spacing of 0.45m is based on standard good practice and our past experience, it is anticipated that a low module tilt angle will most likely be employed once optimisation has been conducted, considering the Project location. As such, the shading reduction benefits from increased spacing is expected to be minimal. Therefore, considerations for inter-row spacing and pitch distance have been primarily based on the minimum width requirement specified by OSHA[10] Elevated Walkway Design Standard. This is to ensure the safety of site operators and space efficiency. The dome configuration (i.e., dual-pitch arrangement) of PV modules is advantageous in terms of reducing wind load on the FPV structure compared to mono-pitch arrangement, especially for high wind areas experienced in the Philippines.
Target DC capacity	139.8 MWp (215,040 units of JKM650N-66HL4M-BDV)	
Target AC capacity	105.6 MWac (24 units of SG4400UD-MV)	
DC/AC ratio	1.3	
Module orientation	Landscape (1 row x 56 columns)	
PV table design	Dome configuration	
Number of modules per string	28	
Azimuth	78° and -102°	
Inter-row spacing (pitch-distance)	0.45m (2.8m)	
Array height above water surface (m)	0.2m	

[10] OSHA = Occupational Safety and Health Administration

Key parameter	Value	Description
Sagay (Stilt-mounted Aquavoltaics on fishpond)		
Coordinates	10.9405°, 123.3919°	Mott MacDonald has assumed plant configurations based on preliminary layout, number of PV modules per string, and DC and AC capacities provided by the Client. Based on our experience, we assume the minimum height above water surface to be 0.5m PV installation in flood prone area and fishpond (i.e. as a safety factor to the maximum water level).
Target DC capacity	126.0 MWp (193,844 units of JKM650N-66HL4M-BDV)	
Target AC capacity	101.2 MWac (23 units of SG4400UD-MV)	
DC/AC ratio	1.2	
Module orientation	Portrait (4 rows x 28 columns)	
PV table design	South facing	
Number of modules per string	28	
Azimuth	0	
Inter-row spacing (pitch-distance)	3.0m (12.5m)	
Array height above water surface	0.5m	
Magat (Floating Solar PV – Membrane-type)		
Coordinates	16.8241°, 121.4527°	Mott MacDonald has assumed a plant configuration based on the DC and AC capacity and key technologies as agreed with the Client. The number, configuration and location of floaters are assumed at a high level to meet the DC and AC capacity constraints provided by the Client and avoid unnecessary string mismatch losses where possible. The height above water surface is assumed to be 0.05m to account for the thickness of the membrane.
Target DC capacity	126.3 MWp (194,350 units of JKM650N-66HL4M-BDV)	
Target AC capacity	101.2 MWac (23 units of SG4400UD-MV)	
DC/AC ratio	1.25	
Module orientation	Portrait (2 rows x 26 columns)	
PV table design	Horizontal to ground, contact with membrane	
Number of modules per string	26	
Azimuth	0	
Inter-row spacing (pitch-distance)	0.35m (5.1m)	
Array height above water surface	0.05m	

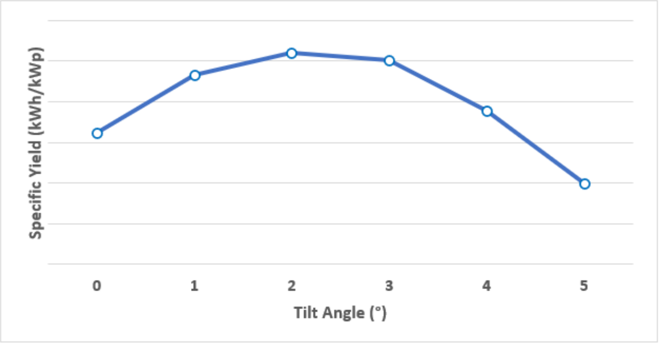
Source: The Client and Mott MacDonald

4.4.1 Tilt angle analysis

An assessment of the PV module tilt angle was conducted by varying the tilt angles with 1° increments from 0° to 5° for the Project with dome configuration (i.e., Laguna Bay) and 5° to 11° for the Project with south-facing configuration (i.e., Sagay), while maintaining all other configurations as shown in Table 4.5. This approach aimed to determine the tilt angle that offers the highest specific yield.

The plot between specific yield figures and associated tilt angle for Laguna Bay with dome configuration and Sagay with south-facing configuration are illustrated in Figure 4.2 and Figure 4.3, respectively.

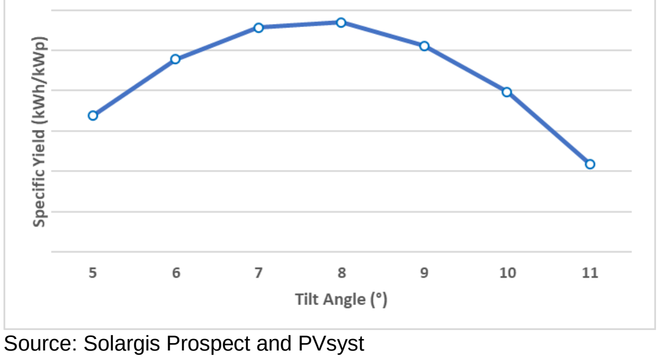
Figure 4.2: Assessment of specific yield optimization for dome configuration plant – Laguna Bay



Source: Solargis Prospect and PVsyst

Figure 4.2 illustrates that the optimum tilt angle is 2° for the dome configuration of Laguna Bay. However, based on common practice and the publicly available literature[11] as the tilt angle becomes increasingly horizontal, the GII decreases and soiling effect increases due to less self-cleaning of PV module. Factoring in considerations for typical O&M requirements to avoid significant dust accumulation, **the module tilt angle of 5° was selected** despite its slight disadvantage in the specific yield.

Figure 4.3: Assessment of specific yield optimization for south-facing configuration plant – Sagay



Source: Solargis Prospect and PVsyst

[11] Jose Cano; Jim Joseph John; Sai Tatapudi; GovindaSamy TamizhMani. Effect of Tilt Angle on Soiling of Photovoltaic Modules. IEEE, 2014

For the south-facing configuration of Sagay, tilt angle of approximately 11° provides maximum GII; however, inter-row shading becomes more significant at such tilt angle and the resulting specific yield is found to be lower than the other tilt angles assessed. Based on the inter-row spacing and location of the Project, the **tilt angle of 8° instead offers the highest specific yield** as it balances between high GII and low inter-row shading effect.

For Magat, tilt angle analysis has not been conducted as the module tilt on the membrane is 0° as the PV modules will be laid horizontal on the membrane surface. This may be disadvantageous in terms of transposition uplift as the PV module will not be optimally positioned for the sun angle of the site. Soiling accumulation may also be another impacted factor as the modules will not be tilted to receive the self-cleaning effect.

4.5 System losses and Performance Ratio (PR)

The losses experienced in a PV system are cumulatively combined to give the Performance Ratio (PR) of the plant, which is a measure of both the performance and the efficiency of the 'on the ground' equipment, and is defined below:

$$PR = \frac{Real\_energy}{Theoretical\_energy}$$

The PR can be predicted based on the proposed plant design and is vital to calculate the expected energy output of the Projects during its operational lifetime. Losses associated with this Project are given in Table 4.6 and detailed descriptions of each loss are further explained in Appendix A. The PR for the Projects has been calculated using PVsyst software and complemented where necessary with Mott MacDonald's in-house modelling.

Table 4.6: System losses breakdown

Losses	Laguna Bay	Sagay	Magat[12]	Description
Far shading	-0.0%	-0.1%	-0.1%	Given the scale of the Projects of which the PV arrays are expected to be installed over a large area, far shading loss is estimated in PVsyst based on the most representative horizon profile identified from different horizon profiles retrieved from Solargis Prospect at several locations within each Project boundary.
Near shading (irradiation, electrical)	-0.1% (-0.1%, -0.0%)	-0.6% (-0.4%, -0.1%)	-0.0% (-0.0%, -0.0%)	The near shading loss is simulated in the PVsyst software based on the 3D plant layout developed by Mott MacDonald based on parameters indicated in Table 4.5, taking into account PV modules orientation and potential surrounding/adjacent shading objects (e.g., inverters and MV stations etc). The electrical shading loss simulation assumes I-shape string wiring configuration as illustrated in Figure 4.1.
Incidence angle	-2.5%	-2.2%	-2.4%	We have applied the Fresnel model with AR coating proposed by PVsyst for estimating the incidence angle loss assuming that new PV coating material is mostly AR coating. This loss can be refined once the IAM characteristic report of the selected PV module model becomes available.

[12] Unlike the Laguna and Sagay Projects, the upside is presented instead of base case due to insufficient information about cooling effect for membrane type floaters available in public domain at the current stage to reasonably quantify the base-case value.

Losses	Laguna Bay	Sagay	Magat[12]	Description
Soiling	-1.0%	-1.0%	-1.0%	The annual soiling loss is assumed at 1.0% based on the assumption that the appropriate PV module cleaning scheme is conducted during dry season. This loss can be revised in case there is soiling warranty or based on specific module cleaning cycles per year to be undertaken during plant operation. In the case of Magat, due to the horizontal laydown (0° tilt angle) of the PV module on the floating membrane, it is envisaged that the Project may experience increased soiling as the design tilt is not conducive to module self-cleaning which is typically expected to materially benefit the PV system when the tilt angle is at least 5° from our experience. While cleaning schemes are typically practiced in the Philippines, we would expect the O&M scheme of a membrane type floating solar PV project to consider a more frequent cleaning as necessary to offset any potential increase in soiling that may result from more dust accumulation on the horizontal PV modules.
Ground reflection on the front	+0.0% (gain)	+0.0% (gain)	-	PVsyst simulation based on the sum of contributions of the reflected irradiation on the front side of PV modules. The magnitude of ground reflection is correlated to the ground albedo and PV modules' tilt angle. An albedo of 0.07 is assumed for systems installed on the water surface.
Spectral	0.0%	-0.5%	0.0%	Mott MacDonald's assumption for crystalline modules considering the estimated irradiation-weighted average Air Mass (AM) of each of Project site relative to the reference AM of 1.5 at STC.
Incident Irradiation on the rear side	+0.2% (gain)	+0.7% (gain)	-	PVsyst simulation based on the sum of contributions of the reflected irradiation on the rear side of bifacial PV module. The rear side gain derived by PVsyst takes into account: • Global irradiation on ground; • Ground reflection loss; • View factor for rear side; • Sky diffuse and beam irradiation on rear side; and • Near shading factor affecting rear side (i.e., assumed as 40.0% and 5.0% for Laguna Bay and Sagay, respectively). Because of limitation in PVsyst bifacial simulation using E-W dome type, this gain is estimated using simplified approach where E-W dome was modelled as flat surface with allowable spacing according to top spacing of PV modules forming E-W dome. For Magat, provided that the PV module shall be installed horizontally and in contact with the membrane such that no significant irradiance may reach the PV module rear side, bifacial gain was not considered for the Project.
Low irradiance performance	-0.7%	-0.6%	-0.6%	We have assessed the low irradiance performance by using Rshunt and Rseries default values for the corresponding ".PAN files" of the selected PV module model for each Project as available in our internal database. Similar to the IAM loss, the low irradiance performance loss can be revisited in case the relevant test results becomes available.

Losses	Laguna Bay	Sagay	Magat[12]	Description
Temperature	-6.9%	-5.7%	-2.7%	Temperature loss is estimated using the PVsyst simulation based on the meteorological data from Solargis Prospect and the PV module's electrical and thermal characteristics embedded in the '.PAN' files obtained from our internal database. In considering the cooling effect from water body based on the mounting structure types, the base case thermal constant loss factor (Uc) for each Project is assumed as following: ● Laguna Bay: 22.0W/m2K; ● Sagay: 29.0W/m2K; and ● Magat: 70.0W/m2K. We recommend this temperature loss assumption to be revisited taking into account the result from on-site temperature validation study to be undertaken based on the floating pilot testbed at the Project site locations. See further explanation and consideration of thermal loss factor in Section 4.9.
Power tolerance	+0.8% (gain)	+0.8% (gain)	+0.8% (gain)	The power tolerance is estimated to be ¼ of the power tolerance range specified in the selected PV module's datasheet available in the public domain. This loss can be refined when the flash test results for the selected PV module model become available.
Light-induced degradation (LID)	-0.6%	-0.6%	-0.6%	The LID value was calculated based on the PV manufacturer's guaranteed value (first year degradation deducted by annual degradation). This loss can be refined when the LID test results of the module model are available.
Static mismatch	-0.6%	-0.6%	-0.6%	Given that the flash test results of the selected module model are not available, the module static mismatch loss is assumed at 4/5 of the power tolerance based on median relationship of mismatch and power tolerance from flash test results collectively available in our in-house database and based on our project experience. A comprehensive assessment of the mismatch loss would necessitate a combined analysis of the flash test results of the module used for the Projects and the procedure followed by the contractor to assemble the modules on site. This loss may be refined when such information becomes available.
Static mismatch for back irradiance	-0.0%	-0.1%	-	For bi-facial system, power mismatch occurs at the rear side due to non-uniformity of the rear irradiance as the worst performing cell limits the current in a string. The PVsyst default factor of rear mismatch loss of 10% is applied in the simulation. For Magat, provided that the PV module shall be installed horizontally and in contact with the membrane such that no significant irradiance may reach the PV module rear side, system loss related to bifacial application was not considered for the Project.
DC wiring loss	-1.0%	-1.0%	-0.9%	DC wiring loss is calculated by PVsyst under the long-term average environmental conditions derived from Solargis Prospect with the assumption of an average DC system voltage drop of 1.5% at STC for central inverters based on the assumption of well-optimised wiring design and our experience on the similar scale projects. This loss can be refined when the DC single line diagram (SLD) with cable specification, size and length become available.

Losses	Laguna Bay	Sagay	Magat[12]	Description
Dynamic MPPT[13] performance	-0.5%	-0.5%	-0.5%	Based on our internal benchmark, the dynamic MPP tracking efficiency loss of -0.5% is assumed for central inverter type for the Projects. This loss can be refined once the dynamic MPPT efficiency test report of the selected inverter is available.
Inverter efficiency	-1.1%	-1.1%	-1.1%	Conversion efficiency loss of the inverter is estimated from the PVsyst simulation based on the '.OND' file of the selected inverter model in our internal database.
Inverter clipping loss	-0.1%	-0.1%	-0.1%	Inverter clipping loss is estimated through PVsyst simulation based on the DC/AC ratios of the Projects.
AC wiring loss (1st stage)	-0.5% (up to busbar of each FPV island)	-0.6% (up to HV transformer)	-0.6% (34.5kV within the FPV island area)	In the absence of supporting information, the 1st stage AC wiring loss is calculated by PVsyst under the long-term average environmental conditions derived from Solargis Prospect with the assumption of an annual average AC system voltage drop of 1.0% at STC within the area of solar PV system installation. This loss is recommended to be refined when the AC SLD with cable specification, size and length become available.
AC wiring loss (2nd stage)	-0.1% (34.5kV line from FPV island to HV transformer)	n/a	-0.3% (34.5kV line from FPV island to HV transformer)	For Laguna Bay, given the considerably large installation area, 34.5kV AC wiring loss from floating islands to the collector substation is separately calculated based on the cable length and types as stated provided in "S-05 (SLD)_Sta Rosa.ver2(with Meralco connection).pdf", using our in-house tool. For Magat, due to significantly large installation of FPV system and distance to the HV transformer, we account for an additional 0.3% AC wiring loss from our typical assumption to capture this extended distance.
MV transformer	-1.0%	-1.0%	-1.0%	Given that specific transformer model has not yet been selected, we have therefore assumed the MV and HV transformer loss of -1.0% and -0.5%, respectively. This loss can be revisited when the transformer models are finalised and that the load and no-load loss information becomes available.
HV transformer	-0.5%	-0.5%	-0.5%	
Transmission loss (up to interconnection point)	-0.2%	-0.2%	-	For Laguna Bay and Sagay, given specific data of the transmission line is not sufficient for our analysis, we have therefore assumed a transmission loss of -0.2% based on our internal benchmark. For Magat, based on discussion with the Client, the location of revenue meter is assumed to be at existing air insulated substation of Magat Hydroelectric Power Plant. Considering close proximity and voltage level of HV system – 230kV, we considered that the transmission line loss is negligible for this assessment.
Auxiliary losses	-0.5%	-0.5%	-0.5%	Auxiliary loss has been assumed by Mott MacDonald's based on our experience given that the proposed load schedule for the Projects is not yet available. For avoidance of doubt, night-time consumption is excluded from this loss. This loss can be revisited when more information regarding the expected internal consumption is available.

[13] Maximum Power Point Tracking

Losses	Laguna Bay	Sagay	Magat[12]	Description
Annual PR Initial (Exclusive of unavailability)	**84.1%**	**85.1%**	**87.9%**	
Plant unavailability	-1.0%	-1.0%	-1.0%	Based on the assumption of a well-maintained PV system during operation and no significant/atypical grid downtime, we assumed -1.0% unavailability reflecting the combination of internal and external unavailability.
Annual PR Initial (inclusive of unavailability)	**83.3%**	**84.3%**	**87.0%**	

Source: Mott MacDonald

4.6 Specific yield

The performance of the plant is influenced by the choice of selected technologies, design, and environment conditions. The specific yield has been calculated to determine the annual yield estimates of the Projects. The specific yield is the product of the GII and the PR of the plant. The summary of plant performance, Global Inclined Irradiation (GII), and yields is presented in Table 4.7.

Table 4.7: Summary of yield estimates at P50

Parameters	Laguna Bay	Sagay	Magat
Equivalent GII (kWh/m^2)	1,766.5	1,908.4	1,861.4
Initial PR (%)	83.3%	84.3%	87.0%
Initial Specific Yield (kWh/kWp/year)	1,471.1	1,608.5	1,620.2
Energy (MWh) at year 1	205,090	202,128	204,145
Energy (GWh) over 20-year period	3,906	3,850	3,888

Source: Mott MacDonald

4.7 Uncertainty analysis

The specific yield and energy production estimated in the EYA are subject to uncertainties which stem from the modelling and the solar resource. The uncertainty level should be independently assessed depending on specific site location, available solar resource, as well as specific plant design.

- Model Modelling Uncertainty

There is an inherent uncertainty in the calculations due to uncertainties related to the software when estimating the various loss factors. Mott MacDonald has estimated modelling uncertainties of 2.8%, 3.1%, and 2.8% for Laguna, Sagay, and Magat, respectively.

- Solar Resource Uncertainty

The solar resource uncertainty is due to the inter-annual variability, the uncertainty relative to the irradiation source, period of the irradiation resource and estimation approach. Mott MacDonald has estimated solar resource uncertainties of 7.1%, 7.3%, and 6.9% for Laguna, Sagay, and Magat respectively, over a one-year return period.

For avoidance of doubt, categories of uncertainty considered do not include future changes in climate (e.g., from climate change or variations in air quality), outside of the range observed from the historical data used as the basis of this assessment.

- Overall Uncertainty

Statistically, it is expected that the mean value of the annual irradiance will approach the mean of the distribution as more years are considered. The variability declines by the square root of the number of years under consideration. The overall cumulative uncertainty for the Projects is presented in Table 4.

Table 4.8: Overall uncertainty for 1, 10, and 20-year return periods

Parameters	Overall uncertainty		
	Laguna Bay	Sagay	Magat
Single year	7.6%	7.9%	7.5%
10 continuous years	7.0%	7.1%	6.9%
20 continuous years	6.9%	7.0%	6.9%

Source: Mott MacDonald

4.8 Expected Net Annual Energy Production

The total energy generated by the PV plant can be calculated using the following formula:

$$Energy = PR \times \left(\frac{Irradiation\ on\ the\ plane\ of\ arrays}{10^3\,W/m^2}\right) \times (Installed\ DC\ capacity) \times Annual\ Linear\ Degradation$$

For our calculations, we have assumed a long-term linear degradation rate of 0.5% per year over lifetime of each Project, based on the conservative findings of a long-term degradation study conducted by the US National Renewable Energy Laboratory (NREL)[14]. We note that the degradation rate of PV modules is dependent with its operating environment (e.g., irradiation, temperature, humidity, etc.) and 0.4% degradation per year is also achievable for monocrystalline modules under optimal operating conditions.

The probability of achieving a given energy yield is represented by a P number, which vary according to the overall uncertainty level derived in Table 4.8. Expected yields are typically expressed as the P99, P90, P75 and P50 percentiles of the assumed normal distribution that our data follow. For example, P90 is the average annual energy production which is exceeded with a probability of 90%.

The summary of estimated total annual energy yield result is presented in Table 4.9 and the total plant energy yield for every year of operation with P50, P75, P90, and P99 for the Projects (including degradation) are shown in Table 4.10.

[14] Photovoltaic Degradation Rates — An Analytical Review

Table 4.9: Yield estimate summary for the Projects over 1, 10 and 20-year return periods

Year		Single year uncertainty			10-year uncertainty			20-year uncertainty		
	P50	P75	P90	P99	P75	P90	P99	P75	P90	P99
Laguna Bay										
Equivalent irradiation (kWh/m^2)	1,766.5	1,675.3	1,593.3	1,452.1	1,683.7	1,609.1	1,480.8	1,684.1	1,610.0	1,482.5
Initial PR (%)	83.3%									
Initial specific yield (kWh/kWp/yr)	1,471.1	1,395.2	1,326.9	1,209.3	1,402.1	1,340.0	1,233.2	1,402.5	1,340.8	1,234.6
Energy (MWh) at year 1	205,090	194,508	184,984	168,592	195,474	186,819	171,924	195,531	186,927	172,119
Energy (MWh) over 20-year period	3,906,455	3,704,892	3,523,480	3,211,255	3,723,297	3,558,449	3,274,734	3,724,374	3,560,496	3,278,449
Sagay										
Equivalent irradiation (kWh/m^2)	1,908.4	1,806.7	1,715.2	1,557.6	1,817.6	1,735.9	1,595.3	1,818.2	1,737.1	1,597.5
Initial PR (%)	84.3%									
Initial specific yield (kWh/kWp/yr)	1,608.5	1,522.8	1,445.7	1,312.9	1,532.0	1,463.1	1,344.6	1,532.5	1,464.2	1,346.5
Energy (MWh) at year 1	202,128	191,357	181,663	164,978	192,512	183,857	168,962	192,580	183,987	169,197
Energy (MWh) over 20-year period	3,850,020	3,644,860	3,460,210	3,142,414	3,666,860	3,502,011	3,218,294	3,668,160	3,504,482	3,222,778
Magat										
Equivalent irradiation (kWh/m^2)	1,861.4	1,767.7	1,683.5	1,538.4	1,774.4	1,696.1	1,561.4	1,774.8	1,696.9	1,562.7
Initial PR (%)	87.0%									
Initial specific yield (kWh/kWp/yr)	1,620.2	1,538.7	1,465.4	1,339.1	1,544.5	1,476.4	1,359.1	1,544.9	1,477.0	1,360.3
Energy (MWh) at year 1	204,145	193,875	184,632	168,723	194,607	186,022	171,246	194,649	186,102	171,392
Energy (MWh) over 20-year period	3,888,462	3,692,839	3,516,772	3,213,748	3,706,773	3,543,248	3,261,808	3,707,579	3,544,778	3,264,587

Source: Mott MacDonald

Table 4.10: Energy production over 20-year period for the Projects (MWh)

	1-year return period				10-year return period			20-year return period		
	P50 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)
Laguna Bay										
1	205,090	194,508	184,984	168,592	195,474	186,819	171,924	195,531	186,927	172,119
2	204,062	193,533	184,056	167,747	194,494	185,883	171,062	194,550	185,990	171,257
3	203,034	192,558	183,129	166,901	193,514	184,946	170,201	193,570	185,053	170,394
4	202,005	191,583	182,202	166,056	192,534	184,010	169,339	192,590	184,116	169,531
5	200,977	190,607	181,274	165,211	191,554	183,073	168,477	191,610	183,179	168,668
6	199,949	189,632	180,347	164,366	190,574	182,137	167,615	190,630	182,242	167,805
7	198,921	188,657	179,420	163,521	189,595	181,200	166,753	189,649	181,304	166,942
8	197,893	187,682	178,492	162,676	188,615	180,264	165,891	188,669	180,367	166,080
9	196,865	186,707	177,565	161,830	187,635	179,327	165,030	187,689	179,430	165,217
10	195,837	185,732	176,638	160,985	186,655	178,391	164,168	186,709	178,493	164,354
11	194,809	184,757	175,710	160,140	185,675	177,454	163,306	185,729	177,556	163,491
12	193,781	183,782	174,783	159,295	184,695	176,518	162,444	184,748	176,619	162,628
13	192,752	182,807	173,856	158,450	183,715	175,581	161,582	183,768	175,682	161,765
14	191,724	181,832	172,928	157,605	182,735	174,645	160,720	182,788	174,745	160,903
15	190,696	180,857	172,001	156,760	181,755	173,708	159,858	181,808	173,808	160,040
16	189,668	179,882	171,074	155,914	180,775	172,772	158,997	180,828	172,871	159,177
17	188,640	178,907	170,146	155,069	179,795	171,835	158,135	179,847	171,934	158,314
18	187,612	177,932	169,219	154,224	178,816	170,899	157,273	178,867	170,997	157,451
19	186,584	176,957	168,292	153,379	177,836	169,962	156,411	177,887	170,060	156,588
20	185,556	175,982	167,364	152,534	176,856	169,025	155,549	176,907	169,123	155,726
Total energy production (MWh) over 20-year period	**3,906,455**	**3,704,892**	**3,523,480**	**3,211,255**	**3,723,297**	**3,558,449**	**3,274,734**	**3,724,374**	**3,560,496**	**3,278,449**
Annual average energy production (MWh)	**195,323**	**185,245**	**176,174**	**160,563**	**186,165**	**177,922**	**163,737**	**186,219**	**178,025**	**163,922**

	1-year return period				10-year return period			20-year return period		
	P50 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)
Sagay										
1	202,128	191,357	181,663	164,978	192,512	183,857	168,962	192,580	183,987	169,197
2	201,114	190,398	180,752	164,151	191,547	182,935	168,115	191,615	183,065	168,349
3	200,101	189,438	179,841	163,324	190,582	182,014	167,268	190,649	182,142	167,501
4	199,088	188,479	178,930	162,497	189,616	181,092	166,421	189,684	181,220	166,653
5	198,074	187,519	178,020	161,670	188,651	180,170	165,574	188,718	180,297	165,804
6	197,061	186,560	177,109	160,843	187,686	179,248	164,727	187,753	179,375	164,956
7	196,048	185,601	176,198	160,016	186,721	178,327	163,879	186,787	178,452	164,108
8	195,034	184,641	175,287	159,188	185,756	177,405	163,032	185,822	177,530	163,260
9	194,021	183,682	174,377	158,361	184,791	176,483	162,185	184,856	176,608	162,411
10	193,008	182,723	173,466	157,534	183,826	175,561	161,338	183,891	175,685	161,563
11	191,994	181,763	172,555	156,707	182,860	174,640	160,491	182,925	174,763	160,715
12	190,981	180,804	171,644	155,880	181,895	173,718	159,644	181,960	173,840	159,867
13	189,968	179,845	170,734	155,053	180,930	172,796	158,797	180,994	172,918	159,018
14	188,954	178,885	169,823	154,226	179,965	171,874	157,950	180,029	171,996	158,170
15	187,941	177,926	168,912	153,399	179,000	170,953	157,103	179,063	171,073	157,322
16	186,928	176,967	168,001	152,572	178,035	170,031	156,256	178,098	170,151	156,474
17	185,914	176,007	167,091	151,745	177,070	169,109	155,409	177,132	169,228	155,625
18	184,901	175,048	166,180	150,917	176,104	168,187	154,562	176,167	168,306	154,777
19	183,887	174,089	165,269	150,090	175,139	167,266	153,715	175,201	167,384	153,929
20	182,874	173,129	164,358	149,263	174,174	166,344	152,867	174,236	166,461	153,080
Total energy production (MWh) over 20-year period	**3,850,020**	**3,644,860**	**3,460,210**	**3,142,414**	**3,666,860**	**3,502,011**	**3,218,294**	**3,668,160**	**3,504,482**	**3,222,778**
Annual average energy production (MWh)	**192,501**	**182,243**	**173,011**	**157,121**	**183,343**	**175,101**	**160,915**	**183,408**	**175,224**	**161,139**

	1-year return period				10-year return period			20-year return period		
	P50 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)	P75 (MWh/year)	P90 (MWh/year)	P99 (MWh/year)
Magat										
1	204,145	193,875	184,632	168,723	194,607	186,022	171,246	194,649	186,102	171,392
2	203,122	192,903	183,706	167,877	193,631	185,089	170,387	193,673	185,169	170,533
3	202,099	191,931	182,780	167,031	192,656	184,157	169,529	192,697	184,236	169,673
4	201,075	190,959	181,855	166,185	191,680	183,224	168,671	191,722	183,303	168,814
5	200,052	189,988	180,929	165,339	190,704	182,291	167,812	190,746	182,370	167,955
6	199,028	189,016	180,004	164,494	189,729	181,359	166,954	189,770	181,437	167,096
7	198,005	188,044	179,078	163,648	188,753	180,426	166,095	188,794	180,504	166,237
8	196,982	187,072	178,153	162,802	187,778	179,494	165,237	187,818	179,571	165,377
9	195,958	186,100	177,227	161,956	186,802	178,561	164,378	186,843	178,638	164,518
10	194,935	185,128	176,301	161,110	185,826	177,629	163,520	185,867	177,705	163,659
11	193,911	184,156	175,376	160,265	184,851	176,696	162,661	184,891	176,772	162,800
12	192,888	183,184	174,450	159,419	183,875	175,764	161,803	183,915	175,839	161,941
13	191,865	182,212	173,525	158,573	182,900	174,831	160,944	182,939	174,907	161,081
14	190,841	181,240	172,599	157,727	181,924	173,898	160,086	181,964	173,974	160,222
15	189,818	180,268	171,673	156,881	180,949	172,966	159,227	180,988	173,041	159,363
16	188,794	179,296	170,748	156,035	179,973	172,033	158,369	180,012	172,108	158,504
17	187,771	178,324	169,822	155,190	178,997	171,101	157,510	179,036	171,175	157,644
18	186,748	177,353	168,897	154,344	178,022	170,168	156,652	178,060	170,242	156,785
19	185,724	176,381	167,971	153,498	177,046	169,236	155,793	177,085	169,309	155,926
20	184,701	175,409	167,046	152,652	176,071	168,303	154,935	176,109	168,376	155,067
Total energy production (MWh) over 20-year period	**3,888,462**	**3,692,839**	**3,516,772**	**3,213,748**	**3,706,773**	**3,543,248**	**3,261,808**	**3,707,579**	**3,544,778**	**3,264,587**
Annual average energy production (MWh)	**194,423**	**184,642**	**175,839**	**160,687**	**185,339**	**177,162**	**163,090**	**185,379**	**177,239**	**163,229**

Source: Mott MacDonald

4.9 Sensitivity Analysis

Due to the additional cooling effect of a water body, PV modules installed above water surface such as FPV and stilt-mounted aquavoltaic are expected to have lower temperature leading to lower PV module thermal loss and higher module performance. According to findings from studies, the temperature of the PV modules installed on water is influenced not only by water-cooling but also by wind cooling effect (i.e., air circulation). The overall cooling effect as well as the proportion of water and wind influences are largely location specific, subjected to the meteorological characteristics, surrounding condition and mounting structure employed (mounting, float type etc.).

Therefore, in order to identify potential variation of the Projects performance and generation due to potential deviation of the thermal loss assumption from the results in Section 4.5 to 4.8, in this sub-section Mott MacDonald has conducted a sensitivity analysis on the cooling effect on each Project's yield generation. For each Project under this assessment, thermal loss factor or heat loss factor (U-value)[15], has been varied up to three (3) scenarios which are defined as **Downside, Base case**, and **Upside,** to capture different cooling effect from wind and water.

The cell temperature and U-value as per following equations:

$$Tcell = Tamb + (1/U) * [Alpha \times Globeff \times (1 - Eff)]$$

$$U = Uc + (Uv \times V)$$

Where:

- Tcell = PV cell temperature;
- Tamb = Ambient temperature;
- Alpha = Absorption coefficient of solar irradiance;
- Globeff = Global effective irradiance (i.e., irradiance available on the surface of PV module); and
- Eff = PV module efficiency;
- U = Thermal loss factor [W/m²·k];
- Uc = Constant component [W/m²·k];
- Uv = Factor proportional to the wind velocity [W/m²·k / m/s]; and
- V = Wind velocity [m/s]

The cell temperature is calculated based on irradiation and ambient temperature retrieved from Solargis Prospect, PV module specifications, along with Uc and Uv values suggested by PVsyst and the findings discussed in following studies[16]:

[15] Heat loss factor, is referred to heat transfer coefficient, determining the heat flux as proportional to the temperature difference between two media.

[16] Project design > Array and system losses > Array Thermal losses (pvsyst.com)

1. **The cooling effect of floating PV in two different climate zones: A comparison of field test data from the Netherlands and Singapore**[17] is based on field tests in 2 different climate zones – a temperate maritime climate (the Netherlands) and a tropical climate (Singapore) conducted by TNO and SERIS, respectively. (For this LCOE assessment, this study is referred to as the 1st study and its findings are utilised for sensitivity cases of Laguna Bay and Sagay)
2. **Field experience and performance analysis of floating PV technologies in the tropics**[18] presents field measurement data, comparing operating environments on water and on a rooftop and analysing system performance of different FPV systems. The testbed is located in the western corner of Tengeh Reservoir (1°N, 103°E), which is close to the western border of Singapore. (For this LCOE assessment, this study is referred to as the 2nd study and its findings are utilised for sensitivity cases of Laguna Bay and Sagay)
3. **Cooling of floating photovoltaics and the importance of water temperature**[19] assesses the effect of water cooling for a membrane type floating technology developed by Ocean Sun where this test bed is installed in Skaftå, Norway. According to the study. due to the direct thermal contact between the modules and the water (i.e., we understand the direct thermal contact implies the efficient heat transfer between the modules and the water through the membrane layer), U-value of approximately 70 to 80 W/m²K should be applied to achieve more correlated result to the measurement of the module temperature, and water temperature and water flow should also be considered in addition to air temperature and wind. (For this LCOE assessment, this study is referred to as the 3rd study and its findings are utilised for sensitivity cases of Magat)

According to the studies, the proportions of Uc and Uv are highly dependent on the design of the floating platform (e.g., free-standing, small footprint, large footprint, membrane type). For large footprint floaters with a closed structure which are expected to experience similar effects as Laguna, the U-value is less dominated by Uv and more dependent on Uc. Conversely, for small footprint floaters with an open structure and free-standing platforms with an open structure which are expected to experience similar effects as Sagay, the U-value is dominated by Uv and less dependent on Uc. In membrane-type floaters which are expected to experience similar effects as Magat, the cooling effect of Uv on the total U-value is expected to be marginal, with Uc having a more dominant impact.

In addition, there are challenges in obtaining reliable wind speed data that can suitably represent the wind condition at the Projects sites, as its measurement depends on factors including height, nearby objects, local weather, etc. In this assessment, we therefore capture the wind cooling effect through the total U-value instead of inputting Uv and wind speed (i.e., U = Uc) in the modelling.

With above considerations, our basis of U-value adjustment in the simulation for each scenario is as below:

- **Base case**

  For Laguna Bay, base case is defined as a scenario when there is limited air circulation – no wind cooling effect but still experience water cooling effect while the base case of Sagay is defined as a scenario when there is no water-cooling effect but experience wind cooling effect.

- **Upside**

  For Laguna Bay and Sagay, the upside scenario is considered to be when PV module experiences both water cooling effect and wind cooling effect.

- **Downside**

  For Laguna Bay and Sagay, the downside scenario is considered to be when neither water-cooling effect nor wind cooling effect is captured.

[17] The cooling effect of floating PV in two different climate zones: A comparison of field test data from the Netherlands and Singapore | Request PDF (researchgate.net)

[18] Liu H, Krishna V, Leung JL, Reindl T, Zhao L. Field experience and performance analysis of floating PV technologies in the tropics. Prog Photovolt Res Appl. 2018;26:957–967.

[19] Cooling of floating photovoltaics and the importance of water temperature (unit.no)

In the case of Magat, unlike the Laguna and Sagay Projects, the sensitivity cases include only **downside** and **base case** while upside cannot be quantified due to insufficient information about cooling effect for membrane type floaters available in the public domain. We also note from the third study above, that water temperature is suggested to be utilised as ambient temperature instead of air temperature; however, accurate water temperature cannot be directly calculated due to complexity of environmental influences (e.g., sunlight, wind, water depth, current etc.) and measurement is not available. Therefore, the water temperature is assumed to be equal to air temperature under this assessment.

Uc for each scenario of the Projects and the reference are summarised in Table 4.11.

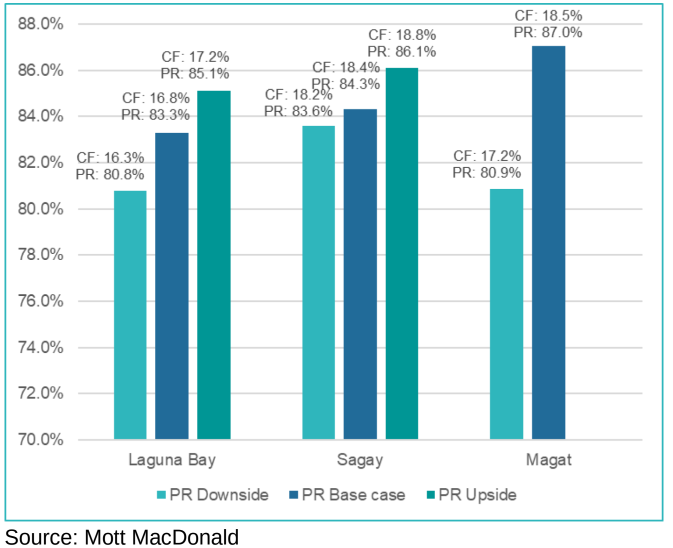
Table 4.11: Uc applied in the simulation for the Projects

Location	Uc			Reference
	Downside	Base Case	Upside	
Laguna Bay	15 (W/m^{2}K)	22 (W/m^{2}K)	36 (W/m^{2}K)	**Base Case:** Uc of 22 (W/m^{2}K) as per median thermal loss factor of insulated float structure (large footprint with dome configuration – dual-pitch) of the 2nd study. **Downside:** Uc of 15 (W/m^{2}K) as per PVsyst recommendation for fully insulated backside **Upside:** Uc of 36 (W/m^{2}K) as per median thermal loss factor of FPV system (large footprint with close structure) of the 1st study.
Sagay	25 (W/m^{2}K)	29 (W/m^{2}K)	55 (W/m^{2}K)	**Base Case:** Uc of 29 (W/m^{2}K) as per PVsyst recommendation for free-standing (open-rack) with air circulation **Downside**: Uc of 25 (W/m^{2}K) as per PVsyst recommendation for the free-standing (open-rack) but neglect Uv component **Upside:** Uc of 55 (W/m^{2}K) as per median thermal loss factor of FPV system (free standing and open structure) of the 1st study.
Magat	15 (W/m^{2}K)	70 (W/m^{2}K)	n/a	**Downside**: Uc of 15 (W/m^{2}K) as per PVsyst recommendation for fully insulated backside **Base case:** Uc of 70 (W/m^{2}K) is assumed based on the stipulated range from the 3rd study analysing the cooling effect for Ocean Sun floaters .

Source: Public domain, PVsyst, and Mott MacDonald

The Initial (Year 0) PR with respective capacity factor and 1st year energy production associated with the downside, base case, and upside cooling effect of the Projects is estimated and presented in the Figure 4.4 and Table 4.12, respectively.

Figure 4.4: Initial PR and capacity factor of the Projects with different Uc



Source: Mott MacDonald

Table 4.12: First year energy production at P50 of the Projects with different Uc

Location	Year 1 Energy Production (MWh)		
	Downside	Base case	Upside
Laguna Bay	199,043 (Uc = 15)	205,090 (Uc = 22)	209,651 (Uc = 36)
Sagay	200,573 (Uc = 25 W/m2K)	202,128 (Uc = 29 W/m2K)	206,509 (Uc = 55 W/m2K)
Magat	189,682 (Uc = 15 W/m2K)	204,145 (Uc = 70 W/m2K)	n/a

Source: Public domain, PVsyst, and Mott MacDonald

For the Client's further consideration, given cooling effect is dependent with micro-climatic conditions and mounting strucutre, in case the revisitation of the Projects' EYA is envisaged during the further development phase of the Projects, we suggest initiating a test bed campaign at the site location (site-specific test bed) in order to capture how the performance of the PV system may be influenced by water-cooling effect. This will be help improving the energy yield modelling accuracy and gain confidence in applying the more representative U factor.

4.10 Conclusion

The representative long-term annual average GHI at the Project for each location is retrieved from the Solargis Prospect. Considering site location, the plant configuration (e.g., PV module orientation and azimuth), and the tilt angle, the annual average GII for the Projects is shown in Table 4.13.

Table 4.13: GII for the Projects

Parameters	Laguna Bay	Sagay	Magat
GHI (kWh/m²/yr)	1,768.5	1,887.1	1,862.6
Uplift (%)	-0.1%	1.1%	-0.1%
GII (kWh/m²/yr)	1,766.5	1,908.4	1,861.4

Source: Mott MacDonald

Based on the available information provided and the assumptions made, the initial plant PR before annual degradation, initial specific yield, energy at year 1 and energy over Project's lifetime at P50 are presented in Table 4.14.

Table 4.14: Summary of yield estimates at P50

Parameters	Laguna Bay	Sagay	Magat
Equivalent GII (kWh/m2)	1,766.5	1,908.4	1,861.4
Initial PR (%)	83.3%	84.3%	87.0%
Initial Specific Yield (kWh/kWp/yr)	1,471.1	1,608.5	1,620.2
Energy at year 1 (MWh)	205,090	202,128	204,145
Energy over 20-year period (GWh)	3,906	3,850	3,888

Source: Mott MacDonald

Based on our research on cooling-effect due to water for different mounting structure technologies, thermal loss factor (Uc) has been varied to define the different yield scenarios. The year 1 energy production of the Projects for each scenario are presented in Table 4.15.

Table 4.15: Year 1 energy production at P50 of the Projects with different Uc

Location	Year 1 Energy Production (MWh)		
	Downside	Base case	Upside
Laguna Bay	199,043 (Uc = 15)	205,090 (Uc = 22)	209,651 (Uc = 36)
Sagay	200,573 (Uc = 25 W/m2K)	202,128 (Uc = 29 W/m2K)	206,509 (Uc = 55 W/m2K)
Magat	189,682 (Uc = 15 W/m2K)	204,145 (Uc = 70 W/m2K)	n/a

Source: Mott MacDonald

5 Cost benchmarking

In this section, we have provided a high-level benchmark of Capital Expenditure (CAPEX) and Operation Expenditure (OPEX) costs for large-scale FPV projects as cost assumptions to the Levelized Cost of Energy (LCoE) analysis of the Projects as presented in Section 6. The cost benchmark presented is based on our experience on large-scale solar PV projects in Asia, with additional commentary and analysis from projects referenced from publicly available information and studies globally. The costs are assumed to cover all facilities up to the interconnection point of the Projects.

5.1 Overview

The cost has been analysed for CAPEX and OPEX. Within each cost category, we have provided a high-level breakdown of the associated cost items as a range shown in U.S. Dollars (USD) per kW of installed peak power, excluding taxes and VAT.

Given that Project-specific cost items can vary significantly based on site characteristics, logistic strategies, and selected technologies, our estimation is based on the current market condition and does not account for industry changes and economic factors during construction phase of the Projects. The project-specific costs, including land acquisition and extensive land preparation works (such as substantially unforeseen lakebed preparation, onshore cut and fill volumes, slope stability protections, and flood defences), are not considered in the cost benchmarking under this section, however have been considered in the LCOE assessment in Section 6.

5.2 CAPEX

5.2.1 CAPEX trends

As floating PV is a much newer technology compared to conventional PV (with only about a decade of history), limited CAPEX and OPEX cost breakdown and their projection is found to be available in the public domain. Therefore, the global cost trends of utility-scale PV systems are firstly discussed and secondly reported costs of floating photovoltaics (FPV) projects as well as the drivers of FPV costs.

5.2.1.1 Utility-scale PV CAPEX trends

IRENA's 2022 publication[20], which analyses the trends of solar PV plants, shows that the total installed costs of utility-scale solar PV plants declined by 81% from 2010 to 2020. As shown in Figure 5.1, the installed cost had reduced from USD 4,731/kW in 2010 to USD 883/kW in 2022. At a global level, cost reductions for modules and inverters accounted for 61% of the drop, largely due to:

- Technology advancements, which led to reduced material intensity;
- Efficiency improvements, which reduced the area required for a given wattage; and
- Automation of manufacturing processes, which led to economies of scale.

Consistent trends have been observed in the more recent years between 2016 and 2020, where there was a relatively consistent annual reduction of installed costs of approximately 15%. As shown in Figure 5.2, most of the reductions in the total installed costs in the first half of the

[20] Renewable Technology Innovation Indicators: Mapping progress in costs, patents and standards, IRENA 2022

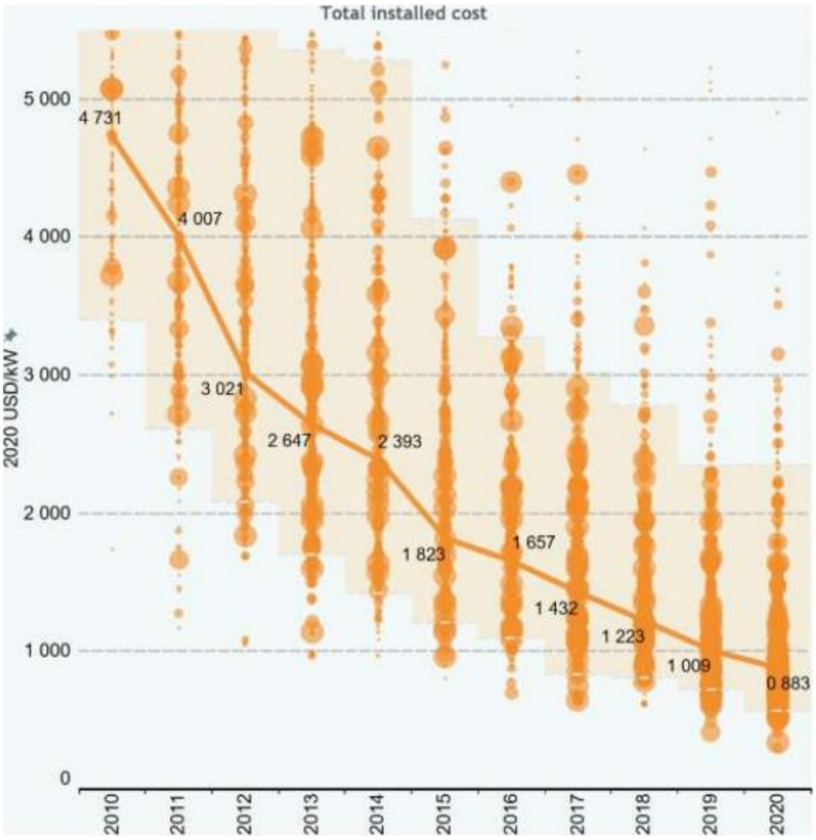
decade were attributable to the decline in module prices. The lowest module price range is reported to be 0.2 - 0.23 USD / kW in 2022. In the recent years, the BoS costs are becoming an increasingly pronounced driver due to increased developer experience, more competitive supply chains, larger project sizes and competitive procurement.

According to IRENA's 2022 publication[20], the range of the total installed costs in 2010 was much wider (USD 3994/KW to USD 9100/kW) compared to that of 2020 (USD 596/kW to USD 1101/kW). Their analysis of 37 countries has shown that, for countries that have grown sufficient developer experience and local supply chains, the costs have converged at or below USD 1,000/kW by 2020. However, there is still some variation in installed costs due to structural reasons including:

- Labour costs;
- Commodity pricing;
- Maturity and scale of local markets;
- Developer experience; and
- Policy and regulatory settings.

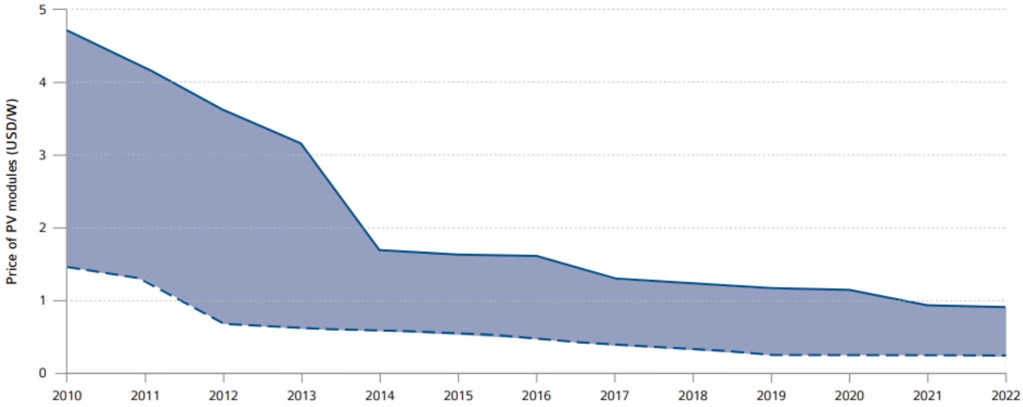
Figure 5.1 and Figure 5.2 shows the trends in solar PV installation cost from 2010.

Figure 5.1: Total installed costs of utility scale solar PV plants



Source: IRENA 2022

Figure 5.2: History of PV module prices



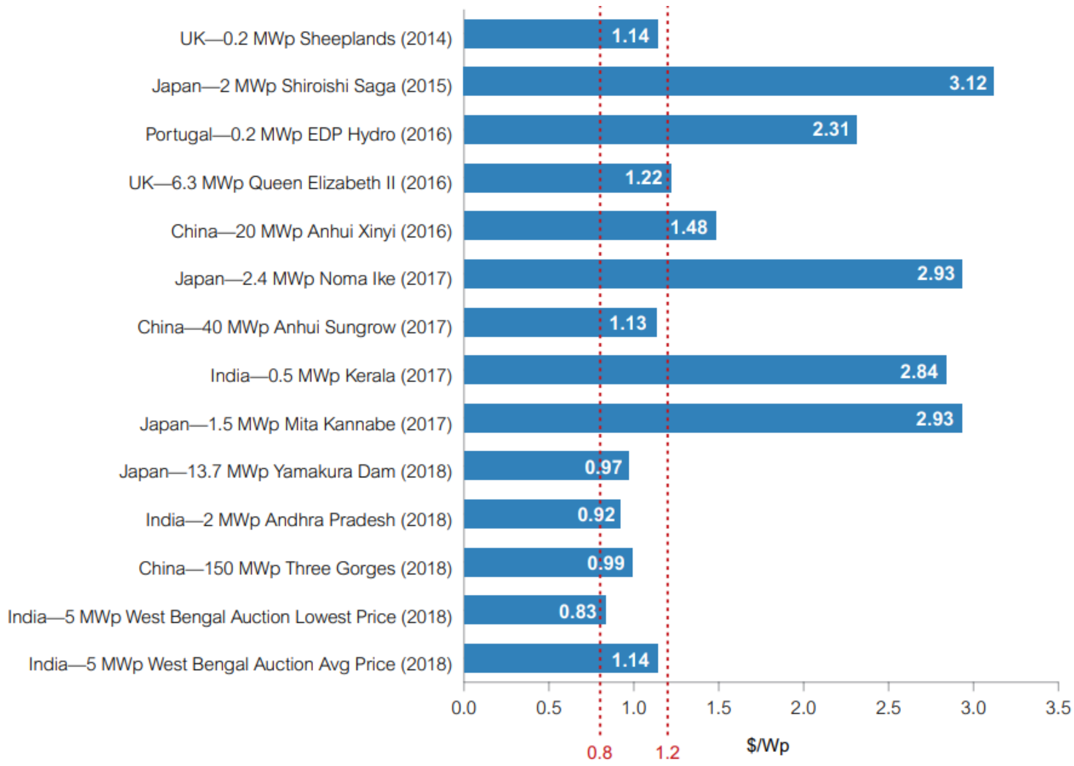
Source: IEA PVPS 2023

5.2.1.2 CAPEX of global FPV projects

According to the floating solar market report published by The World Bank[24], the key difference between the CAPEX of ground-mounted systems and floating systems resides in the floating structure and the related anchoring and mooring system. Another factor that makes floating systems more expensive is the use of electric cables with additional insulation and shielding properties to protect them from moisture degradation. Based on their comparison of 50 MWp ground-mounted and floating systems, they estimate that floating projects are approximately USD 0.10/Wp higher than for ground-mounted systems under the similar conditions.

Figure 5.3 shows the investment costs (realized and auction results) of floating solar PV plants between the years 2014 to 2018. The average total CAPEX in 2018 varied from USD 0.8/Wp to USD 1.2/Wp and notably, the CAPEX of large-scale but relatively simple projects ranged from USD 0.7 – 0.8/Wp. Japan remains a region with relatively high system prices, while China and India achieve much lower prices.

Figure 5.3: Global CAPEX for floating solar PV plants in USD/Wp



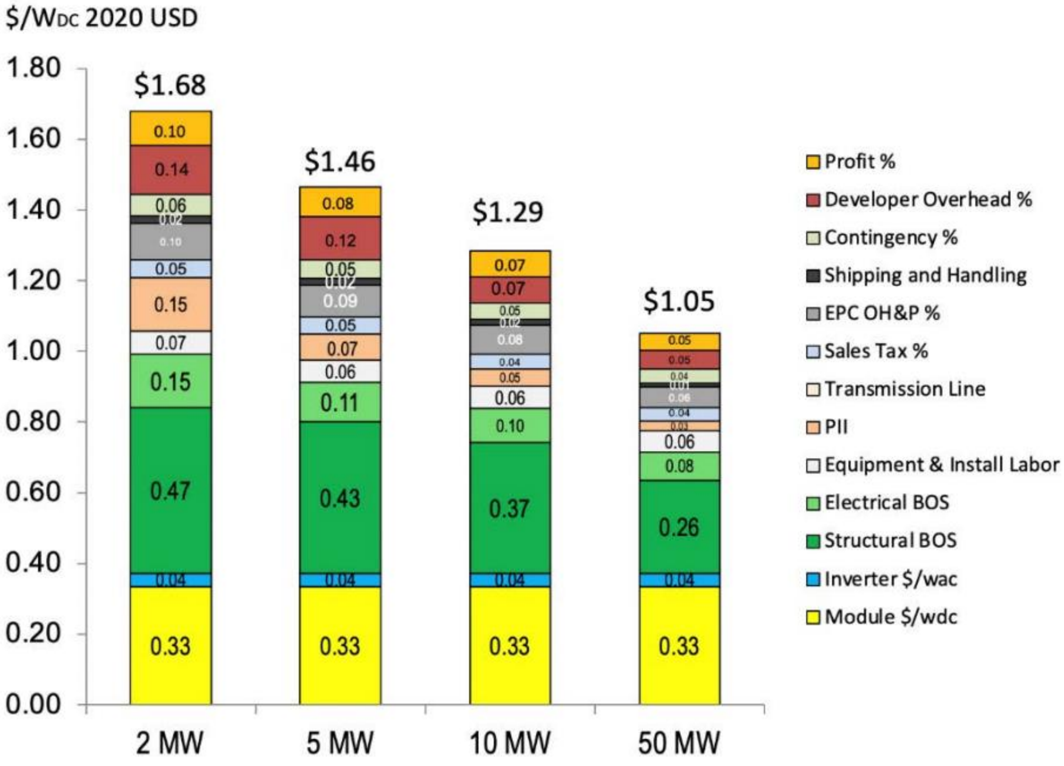
Source: The World Bank 2019

National Renewable Energy Laboratory (NREL)'s report on the cost benchmark of FPV[22] states that the economies of scale of FPV systems are largely driven by structural BoS costs, which account for 25%-30% of the total cost. The main contributor to BoS costs is float costs, where the average cost of floats ranges from USD 0.20/W_{DC} to USD 0.90/W_{DC}, depending on the floating structure type and quantity purchased. Due to economies of scale, the per unit cost of floats decline with increasing quantity of floats purchased. Additionally, it is observed that FPV installation labour and equipment costs can generally be lower than ground-mounted systems attributed to less involvement of high-power installation equipment. Figure 5.4, which shows the benchmark cost of FPV system with varying sizes, demonstrates how larger systems result in lower overall cost.

However, at this time, World Bank states in their market report[21] that optimising the floating platform design by reducing unnecessary buoyancy and some maintenance pathways may be more helpful in reducing the CAPEX as the economies of scale today remain constrained by a relatively small installed capacity.

[21] Where Sun Meets Water Floating Solar Market Report, World Bank 2Group, ESMAP and SERIS, 2019

Figure 5.4: Benchmark cost of FPV system with varying system sizes



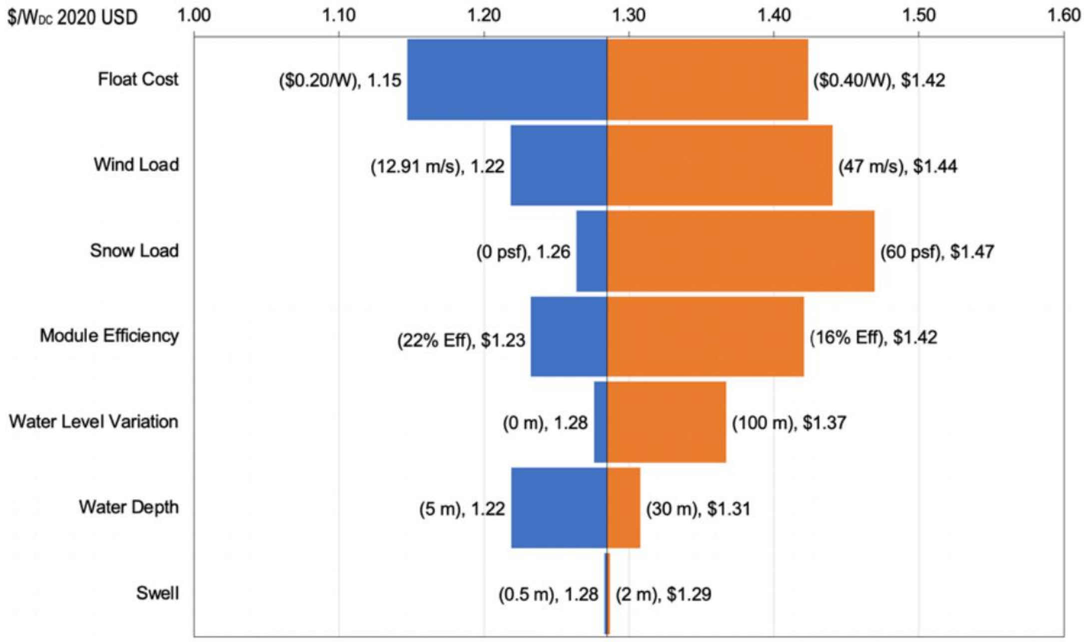
5.2.1.3 FPV CAPEX drivers

The following are the main drivers of CAPEX of FPV projects:

- Anchoring and mooring system and cabling costs, which depend on:
  - Bathymetry (including subsurface soil conditions);
  - Water-level variation (where the level fluctuates widely, more complex mooring is required);
  - Wind and wave characteristics;
  - Type of banks (for launching);
  - Water quality and level of salinity.
- Wind loads: more anchoring points are needed where winds tend to be strong;
- Proximity to the grid infrastructure: longer transmission line will result in increased infrastructure costs.

NREL has determined that the CAPEX of an FPV project is most sensitive to the float costs, wind and snow loading, and module efficiency as shown in Figure 5.5.

Figure 5.5: Sensitivity of FPV installed costs to varying input parameters



Source: NREL 2021

5.2.2 FPV CAPEX structure

CAPEX of FPV projects mainly comprises of Engineering, Procurement and Construction (EPC) cost and non-EPC costs.

EPC costs typically cover following item categories:

- PV modules;
- Inverters;
- Floating structure (i.e., anchoring and mooring equipment);
- Electrical Balance of System (BoS);
- Structural BoS; and
- HV substation up to grid interconnection system.

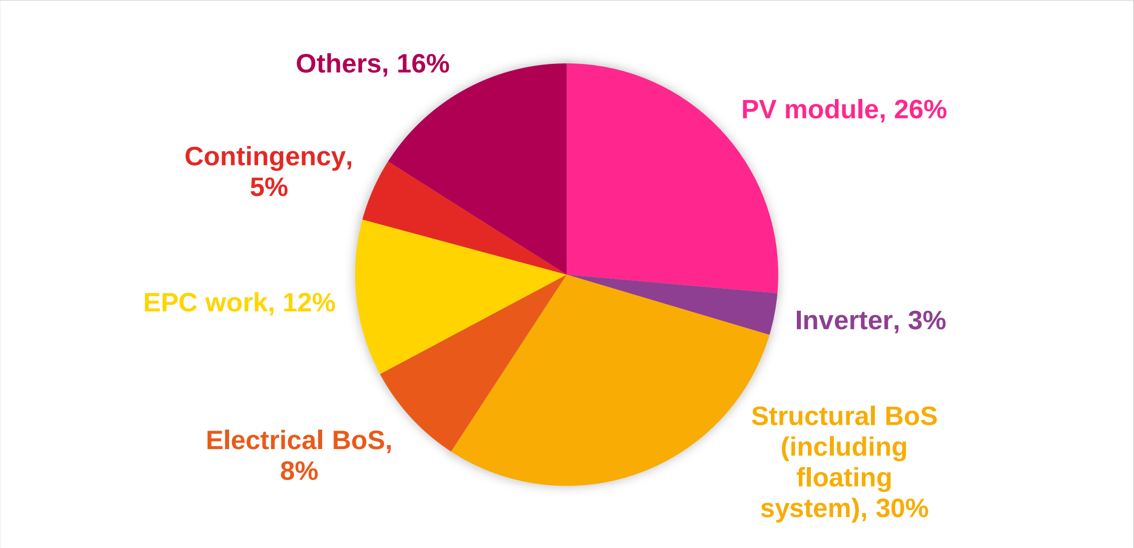
Non-EPC costs typically cover following items:

- Project development cost;
- Advisory and management fee;
- Insurance;
- Financing cost; and
- Construction contingency.

Figure 5.6 shows the percentage breakdown components of typical floating solar PV projects based on a base case scenario floating solar PV system in the United States conducted by National Renewable Energy Laboratory (NREL)[22]. The cost for structural BoS, especially floating structure become a main portion of the total CAPEX besides PV module cost.

[22] Floating Photovoltaic System Cost Benchmark: Q1 2021 Installations on Artificial Water Bodies, NREL

Figure 5.6: Percentage of CAPEX breakdown for floating solar PV projects



Source: NREL

Table 5.1 provides a breakdown of the major CAPEX elements. It should be noted that the breakdown of major CAPEX elements for floating solar PV projects can vary significantly depending on site's characteristics, contract arrangement, project sizes and the range provided is simply inferred from the sample set considered for this high-level assessment. Items in the table are categorized into EPC and non-EPC costs, with subcategories to highlight cost driving items. The average and range of the costs are provided for each item, with general descriptions denoting assumptions for the costs and remarks on the potential impact of site-specific conditions on prices. The estimation is based on our experience with large-scale projects in Asia that were developed between 2019 to 2024, reference to public available information and studies globally.

Table 5.1: CAPEX estimates

No	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments	Remarks for site-specific conditions
A	**EPC cost**	**735**	**540 - 975**	**Our EPC cost range observed from large-scale floating solar PV projects utilising pure floats technology is 530 - 965 USD/kWp.** **With reference to our observation in the last 5 years period, an annual cost reduction of approximately 6% has been observed. The cost trend generally depends on project specification, procurement strategy and market situation.**	**1) Specific to the Philippines** Provided the Project being located in the Philippines where high wind load is expected, more stringent requirements for structural BoS such as anchoring and mooring is expected to drive the cost to the middle to upper end of the range, as mentioned in Section 5.2.1.3. **2) Membrane type floaters** Based on publicly available data, the cost is claimed to be lower compared to the more mature pure float technology. However, we are not aware of such technology being deployed in large scale projects and only limited to small capacity or pilot projects. **3) Stilt-mounted aquavoltaics** Stilt-mounted aquavoltaics, which represent a unique variation of solar PV projects installed over water bodies, such as fishpond or inter-tidal area. Unlike traditional floating solar installations, these systems do not require anchoring, mooring, or floaters. Instead, they rely on bottom-fixed mounting structures and high-powered installation equipment, which influences their cost profile. The primary cost components include materials for the mounting structures and the labour and specialist equipment needed for installation.
A.1	PV module	170	130 – 265	Our PV module cost range is observed at 130 – 265 USD/kWp based on prices quoted from our experience in recent projects. Historically, we observe a general trend indicating a significant decrease in the cost of PV modules over time in line with the public domain study.	The cost of this item may fluctuate depending on the level of Supplier's presence and scope of services available in the region. As discussed in Section 3, bifacial mono-crystalline is preliminarily selected for the Projects. Based on our experience in the current market, there is no significant difference of price range in term of USD/kWp for bifacial PV modules from monofacial ones.
A.2	Floating structure	165	105 – 230	The supply cost of floating structure, including floaters, anchoring and mooring are covered under this item. The figures are based on HDPE floaters and gravity-based anchors.	**1) Specific to the Philippines** The price is driven primarily by design and engineering of the structural components to provide the required reliability for the local environmental load assessment (e.g. wind and wave

No	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments	Remarks for site-specific conditions
					characteristics, water level variation), geotechnical and sedimentation studies (e.g. subsoil and lakebed) – specifically for anchoring and mooring design and technologies. The impact to cost is expected to be on the mid to higher end provided high wind load conditions expected in the Philippines. Cost drivers and the relative impact between the drivers can be seen in Figure 5.5, for which all drivers excluding snow load may potentially impact the overall floating structure cost. **2) Membrane type floaters** For membrane type floating structures, based on publicly available information, the cost is clamed to be on the lower end, attributable to ease of transportation compared to typical floater solutions. Given immaturity of the technology, more data would be required to validate this information from the public domain. **3) For stilt-mounted aquavoltaics** Cost for floating structure is not relevant due to the configuration not having a floating element – but expecting the cost of mounting structure to be higher than typical one as more materials required.
A.3	Inverter	55	40 – 70	The cost range is based on our internal database for inverters including MV transformers. We do not observe significant difference in the different inverter types i.e. central and string.	The cost of this item may fluctuate depending on the level of Supplier's presence and scope of services available in the region.
A.4	Project Substation	25	20 – 30	The EPC costs allocated for the onsite HV substation typically comprising of the supply and installation cost of mechanical works, electrical works, civil works, equipment, Substation Automation System (SAS), etc depending on the project-specific requirements. It is assumed to include the engineering, procurement, construction, installation, and commissioning. The cost presented here is for the substation and equipment and does not yet include the overhead transmission line cost and upgrade works at Connection point. Please see comments under Item A.5 and A.6 for additional details.	Substation cost can vary, driven by the project-specific requirements by the grid owner/operator i.e. NGCP, in addition to Project substation (typically 230kV), upgrade works at/ or newly built NGCP substation may be required.

No	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments	Remarks for site-specific conditions
A.5	Transmission line	To be factored separately	To be factored separately	The overhead transmission line cost is factored external of the site capacity and is primarily dependent on the voltage level and distance of the site to the interconnection point. As such, there is no range or average cost in terms of USD/kWp. Estimates expressed as USD/km is provided as a remark for site-specific conditions.	From our experience with transmission line estimates, the expected cost of overhead transmission line to range from 750,000 – 1,000,000 USD/km, assuming a 230kV, double circuit overhead transmission line with steel towers, exclusive of Right of Way and clearing costs.
A.6	Grid interconnection upgrade works	To be factored separately	To be factored separately	The upgrade works at Connection Point i.e. existing grid substation if required is estimated to be in the range of 5 – 10 USD/kWp based on our project benchmark. The upgrade works mainly comprises of electrical and civil works such as substation equipment, materials, including protection, control, communication, equipment foundation, switchyard, etc.	From our experience in the Philippines, apart from upgrade works which may be required by the grid owner/operator, newly built grid substation/switching station may be required to be built and transferred to the grid owner/operator, cost range could potentially be in similar order to Project Substation.
A.7	Other EPC works	320	245 – 380	The cost is assumed to cover the works of following item categories: • Site studies, design and engineering studies; • Site preparation, temporary and permanent facilities such as laydown areas, launching platform, jetty infrastructure, warehouses, etc; • Civil and structural works,; • Electrical works including Cables and cabling works; • SCADA system; • Construction and project management	**1) Specific to Philippines** Noting that such cost items are relatively project-specific and dependent on the complexity of the Project, as well as the contractual arrangements made with relevant stakeholders. Additionally, the cost component may vary significantly depending on the design works and the local extremity of environmental events that must be accounted for. Given the immature supply, logistic and skilled labour for floating solar projects in the country, this cost can potentially be mid to higher end of the range – until more data is available from other large scale FPV projects in the country. **2) Membrane type floaters** For membrane type solutions, based on publicly available information, the cost for EPC work is claimed to be lower due to ease of installation of the solution. **3) Stilt-mounted aquavoltaics** It is envisaged that this cost may be above average due to the requirements of high-powered specialised installation equipment and skilled labour, and shortage of suitable contractors.

No	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments	Remarks for site-specific conditions
B	**Non-EPC cost**	**210**	**130 – 285**	**All the non-EPC items are considered under this cost, which includes the following:** • **Project development cost ;** • **Advisory fee;** • **Insurance;** • **Financing cost; and** • **Continency.**	We note that costs depend on construction execution plan and strategy, capability and experience of project developers. The project development timeframe, sensitiveness of the nearby communities also affects the project development cost. Costs of land (either lease or purchase) is not included in the provided cost benchmark as this is typically country or area specific.
C	**Total CAPEX [A+B]**	**945**	**670 – 1,260**	**Based on the cost range estimated for each above item, we have aggregated the individual cost components to determine the overall CAPEX (exclusive of transmission line and gird interconnection upgrade works) as average and range values.**	

Source: Mott MacDonald

5.3 OPEX

5.3.1 PV OPEX trends

Since FPV technology is still in its early stage, limited information is available in the public domain. Therefore, we discuss the global trends related to utility-scale PV projects in this section.

As per IRENA's 2022 report[20], the O&M costs of utility-scale solar PV plants have declined in the recent years due to the following factors:

- Improvements in module efficiency has reduced the surface area required per MW of capacity.
- Improvements in the reliability of the technology have resulted in systems that are optimized to reduce O&M costs.
- Innovations such as robotic cleaning and 'big data' analysis, which enable preventative interventions ahead of failures, have driven down the O&M costs and reduced downtime.

NREL found that per the historically reported data, the OPEX and CAPEX reductions are correlated. From 2011 to 2021, the average OPEX and CAPEX costs fell by 58% and 73%, respectively. They forecast that until 2050, property-related expenses will be reduced by the inverse ratio of the increase in module efficiency, which reduces the space and number of modules required.

The benchmark O&M costs for utility-scale PV plants in Southeast Asian countries[23] is reported to be in the range of 6-25 USD 15.4/kW/year (average at USD 15.4/kW/year).

5.3.1.1 Comparison with ground-mounted system

According to IRENA's 2022 report[20], industry representatives state that the O&M costs for FPV projects are comparable to those of ground-mounted projects. However, there are differences in O&M procedures due to the different site conditions and challenges. Table 5.2 shows the comparison of O&M activities with ground-mounted systems.

Table 5.2: Comparison with ground mounted solar

FPV	Ground-mounted
• Harder to access and perform maintenance activities • Biofouling • Animal visits and bird droppings • Easy access to water for cleaning • Lower risk of theft/vandalism • Inspection of anchoring and mooring cables may require divers • Less soiling from dust • More prone to corrosive bird droppings • Temperature fluctuations can cause floats to bloat and shrink (and eventually crack) • Risk of stress due to freezing • Risk degradation and corrosion • Handling of electrical parts on water	• Easy to access for maintenance • Could be affected by vegetation growth • Easier to deploy cleaning routines • Higher risk of theft/vandalism • More soiling from dust

Source: The World Bank

[23] Exploring Renewable Energy Opportunities in Select Southeast Asian Countries, NREL, 2020

While FPV modules generally incur less soiling from dust and has easier access to water (for cleaning), they have been seen to attract birds, which increase the risk of corrosive bird droppings that can negatively affect the energy yield if not cleaned regularly.

Furthermore, the OPEX of FPV systems vary depending on the site's conditions such as wind forces, temperature, and variation of water level, as well as the complexity of maintenance activities, which could be more time intensive for FPV systems and require higher labour cost. Depending on the wind forces present on the site, annual inspection of the mooring cables and sporadic inspection of the anchoring system are performed[24]. Given that O&M activities are more difficult to perform on water than on land, it is important to budget contingency costs for worker safety.

5.3.2 OPEX structure

5.3.2.1 OPEX

OPEX is the project budget to cover the cost arises during the operational phase of the project. The cost typically consists of Operation and Maintenance (O&M) cost and non-O&M cost.

O&M costs typically cover following activities:

- PV module cleaning;
- Operations and monitoring;
- Inspection and Maintenance services; and
- Spare parts.

Non-technical costs typically cover following items:

- Management fee;
- Administrative expenses;
- Insurance; and
- Operation contingency.

Table 5.3 provides a breakdown of the major OPEX elements. It should be noted that the breakdown of major OPEX elements for floating solar PV projects can vary significantly depending on each site-characteristics, contract arrangement, project sizes and the range provided is inferred from the sample set considered for this high-level assessment. Similar to CAPEX estimation, the estimation is based on our experience with large-scale projects in the South-East Asia region that were developed between 2019 to 2024, reference to public available information and studies globally.

Table 5.3: OPEX estimates

No.	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments
A	O&M cost	12	7 – 15	The O&M cost range observed from large-scale floating solar PV projects is 7 – 15 USD/kWp. From available literature, the range for floating solar PV projects are expected to be higher than the range observed for ground-mounted solar PV projects. We would recommend assessing this cost in the middle or upper range given high wind load condition in the Philippines that may prompt more frequent maintenance activities.

No.	Items	Mott MacDonald's Average (USD/kWp)	Mott MacDonald's Range (USD/kWp)	Mott MacDonald's assumptions and comments
B	Non-O&M cost	6	2 – 9	We note that there is a tendency that the insurance premium on floating solar PV projects can be higher than typical solar PV projects[24] in addition to spare parts of floating system. This is further subject to the market status and maturity of a selected technology of PV modules and anchoring and mooring types.
	Total OPEX [A+B]	**18**	**10 – 25**	**Based on the cost range estimated for each above item, we have aggregated the individual cost components to determine the overall OPEX as average and range values.**

Source: Mott MacDonald

5.4 Contingency and Maintenance Reserve Account (MRA)

The typical contingency and total MRA are presented in the Table 5.4 below.

Table 5.4: Contingency and Maintenance Reserve Account estimates

No.	Items	Value	Mott MacDonald's assumptions and comments
A	CAPEX Contingency	Approximately 3% – 5% of total CAPEX	Contingency cost is a portion of project's budget required to put aside for any unforeseen costs, risks, events, or changes in scope that may affect the overall CAPEX cost. A typical assumption of 3 – 5% of CAPEX is recommended to be considered as CAPEX Contingency. However, it is important to note that these values largely rely on the results of the project risk assessment, which reflect the Client's risk appetite.
B	OPEX Contingency	Approximately 5% – 10% of total OPEX	As a standard practice, 5-10% of OPEX is budgeted as part of annual OPEX. Contingency cost is typically budgeted to mitigate risk of unexpected events during the operational phase such as costs not fully covered by warranties, variation in scope of work or potentially underestimated O&M cost.
C	Maintenance Reserve Account	2% of the inverter cost per year during the loan term period	For solar PV plants, we would typically consider the failure rates of the major components of the solar PV plant and propose a MRA balance that is sufficient to provide replacement for this key component once the warranty have expired. Specifically for floating solar projects, we note that PV modules and floaters typically have longer product warranty (e.g. 12-year product warranty or more), which is typically beyond loan term period (e.g. 7-10 years). While replacement costs associated with failure of PV modules, floating/mounting structure, anchoring and mooring, are expected to be covered by OPEX including spare parts budgets. Because of this, the MRA calculated in this section is solely focused on the inverter. We conservatively assume an annual inverter failure rate of 2% of the inverter cost per year to be budgeted during the loan term period. Funding of the MRA is suggested every year during the inverter warranty period to support possible inverter failure after the warranty expires.

Source: Mott MacDonald

[24] Where Sun Meets Water: Floating Solar Handbook for Practitioners, WORLD BANK GROUP, ESMAP, SERIS

5.5 Limitations

We note that limited data is available from the large scale FPV projects in the country to date and the cost benchmark provided have been based on our FPV project experience in Asia and solar PV projects in the Philippines.

Our estimation of the costs in Section 5.2 does not factor in any industry change, supply chain maturity especially floating system which is relatively new in the country or economic factors that may occur during project development. Land acquisition and major land/lakebed preparation activities, right of way or clearing prior to construction, taxes or VAT and custom are deemed to be dependent on project-specific location as well as requirements for grid connection may vary.

5.6 Conclusion

The cost benchmark presented in this section based on our FPV project experience in Asia and solar PV projects Philippines shows a CAPEX in the range of 670 – 1,260 USD/kWp with an average of 945 USD/kWp and an OPEX in the range of 10 – 25 USD/kWp with an average of 18 USD/kWp. The cost benchmark of HV transmission line and works at Connection point are provided separately from the CAPEX.

It is suggested that the FPV CAPEX specific to the Philippines to be assumed in the mid to higher range given challenging wind load condition which would prompt more stringent requirements on design and engineering of structural components for the required reliability and more frequent inspection and maintenance.

For other type of technologies considered by the Client outside of typical pure/HDPE floats i.e.

1) Membrane type floating structures, the cost is claimed to be on the lower end based on the public domain, attributable to ease of transportation compared to typical floater solutions. Given immaturity of the technology, more data would be required to validate this information from the public domain; and

2) Stilt-mounted aquavoltaics, which represent a unique variation of solar PV projects installed over water bodies, such as fishpond or inter-tidal area. Unlike traditional floating solar installations, these systems do not require anchoring, mooring, or floaters. Instead, they rely on bottom-fixed mounting structures and high-powered installation equipment, which influences their cost profile. The primary cost components include materials for the mounting structures and the labour and specialist equipment needed for installation.

Lastly, the typical CAPEX and OPEX contingency are suggested at 3% - 5% and 5% - 10% respectively and a Maintenance Reserve Account of 2% of the inverter cost per year during the 25-year operational period is recommended in line with requirements for projects applying for financing from international lenders.

6 Levelised Cost of Electricity (“LCOE”)

This section outlines the assessment of the Levelised Cost of Electricity (“LCOE”) covering the methodology, basis of the technical and commercial input assumptions, resulting LCOEs, and limitation and boundary of the assessment. The resulting LCOE are based on the result of Energy Yield Analysis for the representative project in each of the locations as outlined in Section 4 and the cost benchmarking activities as outlined in Section 5.

The LCOEs under this assessment will, in total, result in six cases; this includes the LCOEs for each of the two selected projects with three sensitivity cases testing the analysis on the effect of water-cooling effects.

6.1 Methodology

The LCOE presented in this study have been evaluated by calculating the sum of the Net Present Value (“NPV”) of the CAPEX and OPEX (in the year of operation start date), divided by the generation figures (in MWh). The LCOE model (“LCOE Model”) applies the mathematical expression of the LCOE calculation as below:

$$LCOE = \frac{\sum Sum\ of\ annual\ discounted\ costs}{\sum Sum\ of\ annual\ discounted\ energy\ generation}$$

$$LCOE = \frac{\sum_{t=0}^{T}\left(\frac{CAPEX + OPEX}{(1+r)^t}\right)}{\sum_{t=0}^{T}\left(\frac{EYA\ results\ 20\ years\ energy\ generation}{(1+r)^t}\right)}$$

Where:

- T = total years of project lifetime, including both construction phase and operational phase;
- r = annual discount rate
- CAPEX is the investment capital expenditures; and
- OPEX is operations and maintenance expenditures.

It should be noted that the LCOE Model is a simplified model where financing and taxation-related parameters are not considered. The figures used in the study are based on assessments outlined in preceding sections – the Energy Yield Assessment and cost benchmarking. Thus, the resulting LCOEs are subject to the limitations and assumptions discussed in the respective sections.

We applied the key technical and costs assumptions from for each of the cases modelled to the “*Official NREB - Solar Financial Model - GEAP Model.xlsx*” (“GEAR Model”) which is understood to be the basis of the GEAR price evaluation for reference. This is with the aim to account for any financing parameters (e.g. debt and equity, taxation) which is understood to have been captured in the GEAR Model for a comparison purpose.

We highlight that we have not independently verified any assumptions, application and/or financial statement generated in the GEAR Model either on its accuracy or conformance with relevant Generally Accepted Accounting Principles (GAAP).

6.2 Key assumptions and model inputs

Table 6.1 summarised the key technical assumptions which outline the indicative project's performance as well as the assumed technologies as the basis for the cost estimation used within the LCOE model. Whereas Table 6.2 summarised the associated cost assumptions for each of the modelled cases in deriving the resulting LCOEs.

Table 6.1: Technical assumptions in the LCOE model

Parameters	LLDA	Sagay	Magat	Assumptions/Remarks
Targeted DC capacity (MWdc)	139.78	126.0	126.30	Noting that the figures presented in this table is for the 'base-case' scenario whereas the figures used for the sensitivity cases (downside, and upside scenarios) could be referred to in Section 4 of this report.
Targeted AC capacity (MWac)	105.6	101.2	100.0	
Specific yields (kWh/kWp/year)	1,471.1	1,608.5	1,620.3	
Capacity factor (%)	16.8%	18.4%	18.5%	
Floater	Pure floats	Solar on stilt. No floater, anchoring and mooring required.	Membrane-type floater	For LLDA, considering the preliminary information of the Project's location and characteristics, we have assumed the floater technology to be pure floats. For Sagay, no floater is required given the '*Solar on stilt*' setting. The assumption refers to the provided information where the preliminary design for the Project is understood to have been conducted by the Client. For Magat, membrane-type floater is assumed as confirmed by the Client.
Anchoring/mooring	• Self-weight anchoring system; • Fixed length mooring lines		• Self-weight anchoring system; • Fixed length mooring lines	For LLDA and Magat, we have assumed gravity anchoring and fixed length mooring system to be applicable for the Project. Noting that the technical viability of the anchoring and mooring system will be dependent on the specific characteristics and shall be further assessed in detailed based on the availability of such information (e.g., water level variation, bathymetry, soil conditions, environmental impact, etc.).
Transmission and distribution arrangement	Overhead transmission line of approximately 16.2km. Substation is also assumed to be newly built by the Project. One Project's substation will be shared amongst 3 blocks (i.e. 3 x representative project site will share 1 substation)	Overhead transmission line of approximately 11.2km. (From project's substation to Cadiz NGCP). No additional substation construction required.	The Project will utilised existing Magat dam 230kV substation located approximate 1km from the installation area. Step-up HV transformer will be required together with construction of additional bay at existing substation.	The assumption is based on the information provided by the Client. For LLDA, the two routes of transmission line is included – (i) 11.5 km between project's substation to NGCP Calamba and (ii) 4.7km between Calauan grid to Meralco Calauan (transmission route for each location is provided in Section 2). The transmission line cost will be shared by 3 blocks. For Sagay, there is 11.2 km transmission line between the Project's substation to Cadiz NGCP.

Parameters	LLDA	Sagay	Magat	Assumptions/Remarks
			The overhead transmission line of approximately 3km will be constructed.	
Project lifetime	20 years	20 years	20 years	As confirmed by the Client.
Construction period	18 months	18 months	18 months	Assume considering the size of the Project.

Table 6.2: Cost assumptions in the LCOE model

Parameters	Unit	Laguna Bay	Sagay	Magat	Assumption/Remarks
CAPEX					
EPC	‘000 USD				For LLDA, based on the assumption of 755USD/kW (installed) excluding Project’s substation cost., project’s substation cost is assumed at 25USD/kW (installed) which will be shared with another two blocks (FPV system with similar size). This is based on assumption that the Project utilises pure float, self-weight anchoring, and fixed length mooring system. The overall EPC cost falls higher than the mid-range of our benchmark with the consideration of environmental conditions (e.g. water depth, wind, wave conditions etc.) in the Laguna Lake. For Sagay, this is based on the assumption of 690USD/kW (installed). The cost is assessed based on the available aquavoltaic projects benchmarks. For Magat, based on the assumption of 675USD/kW (installed). The main difference from the pure-float type FPV is mainly on the anchoring/mooring and ‘Other EPC’ cost given the relatively less mooring required and less complicated logistics solutions anticipated. The Project’s substation is not required however the cost is in relation to construction on additional bay at the existing substation for the Project.
PV module cost	‘000 USD	23,762	21,420	21,471	
Inverter cost	‘000 USD	7,688	6,930	6,947	
Floater, anchoring and mooring	‘000 USD	25,160	-	18,945	
Others (EPC overhead)	‘000 USD	48,922	58,589	37,890	
Project’s substation	‘000 USD	1,165	-	947	
Transmission line cost	‘000 USD	5,400	11,200	3,000	Based on the average transmission line cost of 1,000kUSD/km. For LLDA, the transmission line cost is assumed to be shared with another two blocks (FPV system with similar size).
Land acquisition cost	‘000 PHP	126,400	-	-	For LLDA, ss advised by the Client. Land for Project’s substation.
Use of waterbodies	‘000 PHP	200,880	6,000	366,824	As advised by the Client
Construction contingency	‘000 USD	7,072	6,230	5,786	Circa 5% of the construction costs (however excluding the waterbody acquisition cost)
Non-EPC Cost	‘000 USD	29,353	26,460	26,523	Based on the benchmarks for similar types of project.

Parameters	Unit	Laguna Bay	Sagay	Magat	Assumption/Remarks
Total CAPEX	**‘000 USD**	**157,409**	**130,937**	**128,108**	**The overall CAPEX equates to specific capital cost ranging at 1,014 – 1,105 USD/kWp.**
OPEX	‘000 USD/year				
O&M fee	‘000 USD/year	1,817	1,638	1,642	Based on the assumption of 13USD/kWp/year.
Non O&M cost	‘000 USD/year	978	882	884	Based on the assumption of 7USD/kWp/year.
Operation contingency	‘000 USD/year	140	126	126	Circa 5% of the construction costs. However, excluding the waterbodies lease fee
Waterbody lease fee	‘000 PHP/year	4,000	6,300	7,304	As advised by the Client
Market fee	‘000 PHP/MWh	0.01	0.01	0.01	0.01
Total OPEX	**‘000 USD/year**	**3,007**	**2,759**	**2,784**	**The overall OPEX equates to specific operating cost range approximately at 21.5 – 22.0 USD/kWp/year.**

In addition to the technical and cost assumptions, the model utilises the macroeconomics assumption as summarised in Table 6.3 to calculate for the LCOE evaluation.

Table 6.3: Macroeconomics assumptions

Parameters	Unit	Assumptions	Remarks
Exchange rate	PHP/USD	55.5886	The relevant costs are benchmarked against USD and therefore the exchange rate is used.
Discount rate	%p.a.	10%	The assumption used to calculate for the NPV of generation and cost items. In general, the assumption is based on the expected returns from the developer.
Inflation rate	% p.a.	4% p.a.	Inflation is used to apply to the inflated cost during the operating years (i.e. operation and maintenance cost)

Note that these parameters are non-technical and further subject to Client's preferences. Variations in these parameters will impact the results of the LCOE under this assessment.

6.3 LCOE results

The resulting LCOE from the assessment and assumptions previously outlined in this report are presented in this subsection. Table 6.4 presents the resulting LCOE noting that this is based on the Projects' energy yields at probability of exceedance at P50. We also highlight that the LCOE figures in Table 6.4 are the results from the simplified LCOE model which does not take into account the financing and taxation parameters and therefore the LCOE figures is further subjected to such parameters.

We have however, attempted to input the key parameters from our assessment (i.e. CAPEX and OPEX estimates, energy yields) into "*Official NERM – Solar Financial Model – GEAP Model.xlsx*" for references. The resulting LCOE in such case is further discussed in subsequent subsection.

Table 6.4: LCOE results from LCOE Model

Cases	LCOE results (PHP/kWh)		
	LLDA	Sagay	Magat
Base Case	6.3364	5.5295	5.3923
Upside Case	6.1988	5.4124	N/A
Downside Case	6.5286	5.5723	5.8027

Source: Mott MacDonald

From the above, the LCOEs ranges at **5.3923 – 6.5286 PHP/kWh** (pre taxation and financing parameter).

6.4 Comparison against GEAR Price

Further to the LCOE evaluation, we have conducted a comparative analysis on between the LCOE results under this study and the Green Energy Auction Reserve (GEAR) price for the second round of auction as established by the Energy Regulatory Commission (ERC) in the Resolution No.06 ("GEAR Price Resolution")[25].

[25] Resolution No.06, series of 2023 – A resolution adopting the Green Energy Auction Reserve (GEAR) prices for the second round of Auction.

The GEAR price under the GEAR Price Resolution was calculated at **PHP5.3948/kWh** for the second round of Auction.

Table 6.5 compares the key assumptions used in the evaluation of the LCOE and GEAR prices are compared and discussed.

Table 6.5: Comparison of assumptions in LCOE and GEAR models

Parameters	Unit	LCOE Model	GEAR Model	Remarks
Technical assumptions				
Installed capacity	MW	126.0 – 139.8	50	
Project operating life	Year	20	25	
Construction period	Month	18	12	LCOE Model assumption based on size of the Project.
Net capacity factor	%	16.3 – 18.8	19.8842%	
Plant degradation	% p.a	0.5%	0.5%	
Cost assumptions				
CAPEX	USD/kWp	969 – 1,054	1,011	
VAT	%	N/A	12%	
Contingency	% of the CAPEX	5%	2%	
OPEX	USD/kWp/ year	21.5 – 22.0	15.5	The figure in GEAR price was converted from the assumption of PHP43,081,165 per year (using fx rate of 55.5886PHP/USD)
VAT recovery level	-	N/A	100% VAT	The LCOE model did not take into account the taxation.
VAT recovery period	years	N/A	5 after COD	
Macroeconomic assumptions				
Exchange rate	PHP/USD	55.5886	55.5886	
Local inflation	% p.a.	4%	0%	Local inflation applies mainly to operating costs.
Discount rate	%	10%	9.4% (see remarks)	LCOE model calculates evaluates the LCOE with the NPV (using the discount rate of 10%). Whereas, the GEAR model applies Pre-tax WACC[26] as the discount factor.

Source: Mott MacDonald, GEAR Price Resolution

It should be highlighted that the assumptions summarised in Table 6.5 does not include other financial and taxation related parameters applied in the GEAR price (i.e. debt and equity and tax assumptions) given such parameters were not applied to in the LCOE Model, however the full list is available in Appendix B.

While the above is noted, we have attempted to apply the key assumptions in the LCOE Model to the financial model titled "*Official NREB - Solar Financial Model - GEAP Model.xlsx*" ("GEAR Model") which is understood to be the basis of the GEAR price evaluation.

The results of the LCOE figures upon using the GEAR Model are summaries in Table 6.6.

[26] The parameter is calculated with other taxation and financing assumptions which was not captured in the LCOE model. The full list of assumptions under the GEAR model could be referred to from and also available in Appendix B of this report.

Table 6.6: LCOE results from GEAR Model

Cases	LCOE results (PHP/kWh)		
	LLDA	Sagay	Magat
Base Case	7.1074	6.3776	6.2556
Upside Case	6.9901	6.2753	N/A
Downside Case	7.2693	6.4148	6.6125

Source: Mott MacDonald based on GEAR Model

From the above, the LCOEs ranges at **6.2556 – 7.2693 PHP/kWh** (incorporating taxation and financing parameter).

We highlight the figures are provided for reference and we do not necessarily confirm the accuracy of resulting figures from the GEAR Model as we have not independently verified any assumptions, application and/or financial statement generated in the GEAR Model either on its accuracy or conformance with relevant Generally Accepted Accounting Principles (GAAP).

A screenshot of the changes in assumptions made to the GEAR Model as part of this exercises is also provided in Appendix B.

The assumptions that were adjusted to the GEAR Model includes:

- Construction period;
- Operating period;
- Plant capacity;
- Net capacity factor;
- Project investment cost and contingency; and
- O&M cost

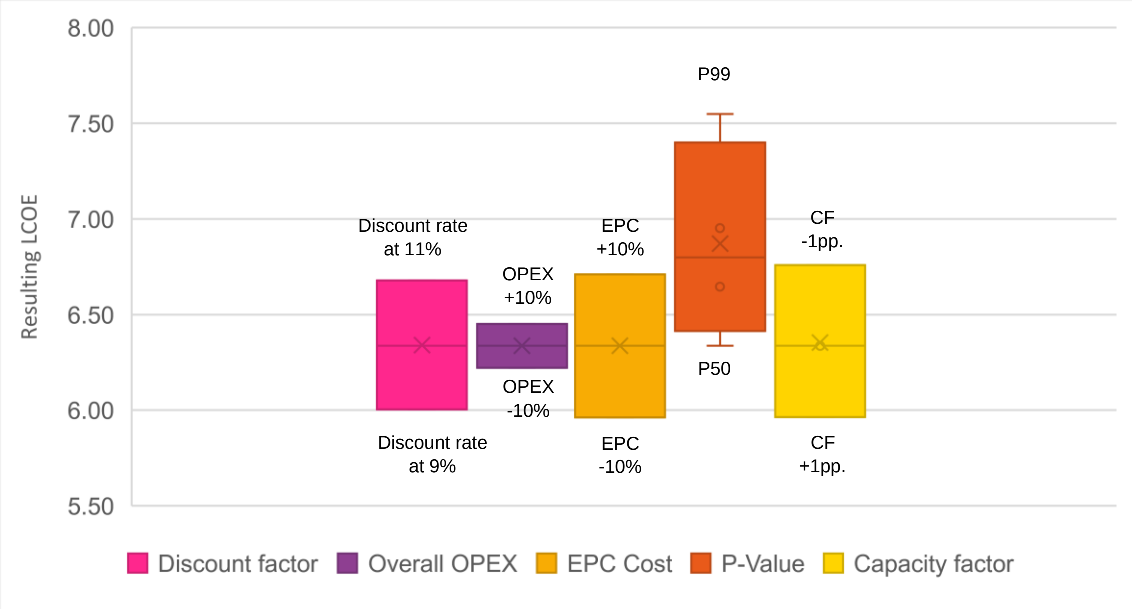
It is worth highlighting that the GEAR Model has also take into consideration the "Feed-in-Tariff" assumptions for the calculation of the resulting tariff (where deviation in that appears to have impact on the financing parameter e.g. WACC) however, we have not adjusted such figure under this assessment and left as originally assumed in the GEAR Model (i.e. 5.9480 PHP/kWh).

6.5 Sensitivity Analysis

Further to the above, we have conducted a sensitivity analysis for the variation of the main LCOE contributors – energy yield's probability of exceedance, EPC cost, OPEX, and discount rate. Figure 6.1 presents the sensitivity on the LCOE from the variation of such factors. The lower and upper bounds represent the LCOE in the following cases (noting that the ranges in Figure 6.1 is referenced from the LCOE results from *LLDA base case*):

- Discount factor varies ranging +/- 1% per year,
- Overall OPEX and EPC cost ranging at +/- 10%; and
- P-values from P50, P70, 90 and P99
- Capacity factor ranging at +/- 1 percent point.

Figure 6.1: LCOE sensitivity analysis



Source: Mott MacDonald,

From the above, the factor that expect to have relatively high impact on the LCOE are the parameters related to estimate generation – probability of exceedance cases (p-values) and capacity factor in this case, and the discount factor used in the LCOE evaluation. One percent point (1 pp.) variation in the capacity factor results in approximately 0.30 – 0.34 PHP/kWh, whereas approximately 0.35 PHP/kWh of variation in the LCOE is observed from 10% deviation in EPC Cost.

6.6 Conclusion

Based on the assessment of three representative locations for the development of FPV projects in the Philippines, the LCOE results in **5.3923 – 6.5286 PHP/kWh** (from the LCOE Model without accounting the financing and taxation parameters) and **6.2556 – 7.2693 PHP/kWh** (based on the GEAR Model). The results show that for considered cases based on the GEAR Model, the LCOE results are higher than the currently proposed GEAR Price of **5.3948 PHP/kWh.** We note that the main difference in the assumption under the two models are the OPEX costs and the assumed capacity factor.

The sensitivity analysis revealed that the primary factors impacting the LCOE figures are the parameters related to estimated generation, such as capacity factor and probability of exceedance cases.

A. Description of PV System Losses

A.1 Spectral Loss

Any PV system will mostly experience radiation with a non AM1.5 spectrum. The spectral shift depends strongly on the location of the module, as it is dependent on parameters such as water vapour, air particles, ozone content etc. Cloudy days are rather characterised by spectrums shafted to blue while sunny days are rather characterised by spectrums shifted to red. Additionally, each PV module technology shows a different spectral response and therefore has different spectral losses.

Crystalline silicon PV modules exhibit greater sensitivity to long wavelength visible light (i.e., red light at the edge of the visible spectrum), which is less susceptible to scattering by the atmosphere than short wavelength visible light (i.e., blue light at the edge of the visible spectrum). An AM value exceeding 1.5 implies that the spectrum of the incident light on the PV array will contain a higher relative intensity of long wavelength light than the AM1.5 spectrum and vice versa. For a given humidity level, crystalline silicon PV modules will therefore perform with slightly higher conversion efficiency relative to receiving the same measured insolation at AM1.5 spectrum (i.e., a minor “gain” relative to STC performance, rather than a loss).

A.2 Shading Loss

Shading losses are originated from surrounding objects that have been designed out of an ideal system, which are generally limited by the space available for the solar farm. It would highly affect shading loss to have a system with trees or buildings that could shade on the modules’ area at any time of day due to the high impact of shading on any part of the installation. The current of any module in shade will control the current of the other modules in the string, depending on the number of bypass diodes, which is usually very low to save costs.

Shading is most likely to be caused by other rows of panels at the extremities of the day and in winter. Shading losses are varied depending on the design of the plant, the closer the rows of panels the more shading is likely to occur. In addition, shading loss is quantified as a combined effect resulting from Irradiance loss from shading and Electrical loss occurred due to the mismatch in current of shaded modules with respect to unshaded modules in arrays.

A.3 Low Irradiance Loss

Under real conditions solar irradiation will be less than the STC irradiance of 1,000W/m^2 for the majority of the time. Depending on the module in question, the cell will perform less efficiently at low irradiation values. Typical values for low irradiance losses averaged over the course of the year are between 1.0-3.5%.

A.4 Angular of incidence and reflection losses

Another influence on received radiation is the angle of incidence. As the sun moves through the sky the angle of the direct sunlight on the fixed panel will change. For non-zero angles of incidence reflection losses occur between the module layers. Both angle of incidence losses and reflection losses increase significantly with incidence angles above 60°. However, the proportion of time spent where the incident angle is above this will be small. Anti-reflective coatings are commonplace on the surface of the panels. However, they will not completely mitigate this loss, which we would expect to be up to 3.5%.

A.5 Ground reflection on the front side

The reflected irradiance on the front side of PV modules – simulated by PVsyst is due to a contribution of albedo reflexion reaching the front side of the collector. The magnitude of ground reflection 'gain' strongly depends on the ground albedo between PV sheds and PV module tilt angle.

A.6 Incident irradiation on the rear side

The reflected irradiance on the rear side of bi-facial PV modules – simulated by PVsyst is based on the sum of contributions of the reflected irradiance on the rear side of bi-facial PV modules. The magnitude of reflected irradiance 'gain' on the rear side of bi-facial modules is derived by taking into account the following factors:

- Global irradiance on ground;
- Ground reflection loss;
- View factor for rear side;
- Sky diffuse and beam irradiance on rear side; and
- Near shading factor affecting rear side.

A.7 Temperature Loss

The efficiency of crystalline silicon PV cells decreases at a rate of approximately 0.2-0.5% per °C above STC temperature of 25°C. Modules can heat up to 70°C causing increased recombination of the electron-hole pairs across the p-n junction which results in less power output. The magnitude of the effect depends on the local environment, the insulation of the back of the cell and the specific cell in question. Temperature losses usually vary between 1 and 10% as a yearly average.

A.8 Power tolerance and Mismatch Losses

Due to the inherent inaccuracy of the silicon photovoltaic manufacturing process, each cell will be slightly different in terms of performance. The range of possible power output is accounted by a positive power output tolerance in the PV module specification. Such 'positive tolerance' modules have become more commonplace in the PV industry.

The relatively small heterogeneity among modules is the basis of the mismatch loss. The mismatch loss depends on an individual characteristic of PV modules and also on the process assembling the modules on site. Similar to the shading loss, the mismatch losses are caused by variations across individual cells, with the string output being determined by the worst performing module.

Typically, there will be slightly different power output for each module which results from the inaccuracy of the manufacturing process. For the current PV market, we expect the 'positive' power tolerance to be observed which implies that the module will have power output higher than the nameplate capacity.

A.9 Mismatch for back irradiance

For bi-facial system, power mismatch – simulated by PVsyst occurs at the rear side due to non-uniformity of the rear irradiance as the weakest cell limits the current in a string. The PVsyst allows the factor of rear mismatch loss to be defined. The default value is set at 10% which is a rough estimation as indicated by PVsyst manual.

A.10 Light-induced Degradation Losses

Light-induced degradation (LID) is defined as the module degradation in the first exposure to sunlight or the module degradation in the first year in excess of the long-term linear degradation applied.

A.11 Soiling

Although the module's coatings are dust repellent, they will invariably collect dirt over their lifetime which will restrict the sunlight able to get to the cell and cause a small loss. It is a common practice in PV installations to specify a cleaning regime in the maintenance plan; however, care must be taken not to scratch the surface as this will cause a more permanent negative effect.
Mott MacDonald would expect soiling losses to be approximately 1 to 2% given a typical site without significant nearby sources of dust. Mott MacDonald believes these values to be important factors when calculating the performance of the plant and dependent on the site conditions as well as the cleaning regime proposed for the plant.

A.12 Wiring Losses

Within the panel to inverter cables and the inverter to meter cables will be an I^2R loss. This loss is inevitable, and Mott MacDonald would expect the plant to be designed in order to minimise the length of the cables as well as cables specified for low losses. Mott MacDonald would expect that the DC plus AC wiring losses (including transmission line loss) to be lower than 3%.

A.13 Inverter Losses

The inverter in the Project has multiple roles, each with an associated loss. These include:

- Maximum Power Point Tracking;
- DC to AC conversion; and
- Inverter curtailment loss.

The total inverter loss will encompass these losses which are inherent in each process. The most important part of the design of the plant is the correct sizing of the inverters in order that the correct balance between expense (size) and Watt peak is achieved.

Maximum power point tracking which controls the panel voltage in order to increase the current and maximise the power output is vital in any PV system. As incident irradiance changes, cell voltage needs to change accordingly in order to optimise cell performance. There are many algorithms employed to determine the Maximum Power Point (MPP). Each of these algorithms has an associated loss under dynamic conditions. The dynamic MPP tracking efficiency refers only to the accuracy/quality of the tracking algorithm and is independent of the number of inverters. The IV curve of the array has a very small influence on this loss as the slope of the curve determines the precision with which the tracking has to operate.

The inverter clipping (curtailment) loss happens when the input DC power to the inverter exceeds the inverter maximum DC power input rated capacity.

A.14 Transformer Losses

In order to achieve grid export voltage, it is necessary to step up the voltage from the inverter output. Mott MacDonald uses standard methodology based on single line diagram and the electrical specifications (i.e. load/no load losses at full load) of the selected transformers provided to estimate transformer losses.

A.15 Auxiliary Loads Losses

Day-time auxiliary loads such as lighting, array box power consumption, ventilator, SCADA and other auxiliary units' consumption, etc. are taken into account as losses for the PV system depending on project design and requirement of the grid.

Any night-time energy consumption including transformer no-load losses are purchased from the grid at a different tariff rate. This means that the night-time consumption is excluded from this energy yield assessment, however, it should therefore be included in the Client's financial model as an operational expense.

A.16 Availability

Availability accounts for the operation and maintenance of the whole system including the substation and inverter failure. Furthermore, availability also accounts for forced outages due to occasions where the Grid Owner disconnects a power plant from their grid to maintain grid stability or due to faults occurring on the grid. Mott MacDonald would typically expect fixed PV system availability to be greater than 98% due to the inherent reliability of the equipment and grid. For EYA for a solar PV plant without atypical disturbance to the power export, a standard 99% availability is considered achievable.

B. Assumption in GEAR Price Resolution

Table 5. Floating Solar GEAR2 Price Parameters

Parameters	GEAR PRICE
TECHNICAL & EPC ASSUMPTIONS	
1. Installed Capacity	50MW
2. Project Economic Useful Life	25 years
3. Construction Period from finance closing	12 months
4. Net Capacity Factor	19.8842% AC
5. Plant Degradation	0.5% / yr
6. Equipment Cost, Transportation to project site, Balance of Plant	US$1,010,929.5/MW
7. Switchyard and Transformers	
8. Transmission Interconnection Distance	
9. Transmission Interconnection Cost	
10. Access/ Service Roads Distance	
11. Access/ Service Roads Cost	
12. Other Development Costs	
13. Value-Added Tax on Importation	12%
14. Initial Working Capital	0% of EPC
15. Contingency Allowance	2% of total cost
OPERATING ASSUMPTIONS	
16. O&M Cost and G&A cost	PhP43,081,165/yr.
17. Spare parts, tool & equipment ($000MW/year)	Included in the O&M Cost
18. G&A Cost ($000/yr)	Included in the O&M Cost
19. Average Fuel Cost	N/A
20. Feed Rate (kWh/ton)	N/A
21. VAT Recovery Level	100% of VAT
22. VAT Recovery Period	5 years after COD
DEBT & EQUITY ASSUMPTIONS	
23. Local-to-Foreign Capital Ratio	70:30
24. Upfront and other Financing Fees	2%
25. Commitment Fees	0.50%
26. Interest Rate – Local Debt	7.36%
27. Interest Rate – Foreign Debt	7.36%
28. Repayment Period – Local Debt	10 years from end of Grace Period
29. Repayment Period – Foreign Debt	10 years from end of Grace Period
30. Grace Period – Local and Foreign Debt	6 months from COD
31. Debt-to-Equity Ratio	70:30
32. WACC – Pre Tax Rate	9.4%
33. Onshore Equity IRR	12.75%
TAX ASSUMPTIONS	
34. Income Tax Holiday (ITH)	7 yrs. from COD
35. Income Tax Rate after ITH	10%
36. Property Tax Rate	1.5%
37. Property Tax Valuation/ Assessment Level	80%
38. Local Business Tax Rate	1%
39. Government Share	1%
40. ER 1-94 Contribution	1 centavo per kWh
41. Withholding Tax on Interest (Foreign Currency)	10%
42. Gross Receipts Tax on Interest (local currency)	5%
ECONOMIC ASSUMPTIONS	
43. Forward Peso to US$ Exchange Rate	PhP55.5886:US$1
44. Local Inflation Rate	0%
45. Foreign Inflation Rate	0%
46. Base PhP to US$ Exchange Rate	PhP55.5886:US$1

Source: Resolution No.05, Series of 2023 – A Resolution Adopting the Green Energy Auction Reserve (GEAR) Prices for the Second Round of Auction dated 14 June 2023.

C. GEAR Model (application in the study)

The GEAR Model refers to the worksheet titled "*Official NREB - Solar Financial Model - GEAP Model.xlsx*" provided by the Client.

The GEAR Model results presented in Section 6 was reported from the results returned from the GEAR Model in '*Asset Base FiT*' (as shown in Figure C.2). Where for each case, the changes in assumptions only applied to the cells in green in the model's assumption sheet (as shown in Figure C.1)

Figure C.1: GEAR Model '*input and assumption*' sheet

Representative Solar Power Project in the Philippines
Key Inputs and Assumptions

Renewable Energy Source	**Solar**
Timing	
Construction Period (from FC) (mos)	12
Operating Period (yrs from COD)	25
Yrs from base year CPI & Forex (2009) for FIT	0
Yrs from base year CPI (2011) for Capex	0
Yrs from base year CPI (2011) for Opex	0
Construction Sources and Uses of Funds ($000)	
Uses of Fund:	
EPC (Eqpt, bal. of plant & tranport)	$ 50,550
T-line Interconnection facility	-
Sub-station facility	-
Development & other costs	-
Construction contingency	1,011
Value added tax	1,948
Financing costs	2,484
Initial working capital	-
Uses of Fund	$ 55,994
Sources of Fund:	
Debt	$ 39,196
Equity	16,798
Sources of Fund	$ 55,994
Construction Cost Metrics (USD/kW):	
EPC cost	$ 1,011
Plant cost excl VAT & financing	$ 1,031
All-in Installed Project Cost	$ 1,120
Model Check:	
Balance Sheet	OK
Foreign Debt Amorization	OK
Local Debt Amortization	OK
Depreciation	OK
Sources and Uses of Funds	OK
Debt-to-Equity Ratio	OK

Technical and EPC Assumptions		
Unit Capacity of Plant	50.0	
No. of Units	1.0	
Gross Installed Capacity (MW)	50.0	
Plant Availability Factor %	19.9%	
Guaranteed Efficiency Factor %	100.0%	
Allowance for losses and own use	0.0%	
Net Capacity Factor after losses & own use %	19.88%	
Net Electrical Output (MWh in 1st Year)	87,093	
Plant Degradation (%/Year)	0.5%	
		% LC
Equipment Cost ex BOP & transport ($000/MW)	1,011	69%
Tranportation cost to site (% of Equipment)	0%	100%
Balance of plant (% of Equipment)	0%	100%
T/line distance (km)	-	
T/line cost per km - 13.2kV ($000/km)	-	100%
Switchyard and transformers ($000)	-	100%
Access roads ($000/km)	-	100%
Distance of access road (km)	-	
Dev't. & others (land, permits, etc) (% of EPC)	0.0%	100%
VAT on importation (70% recoverable)	12%	100%
Initial Working capital (% of EPC)	0.0%	100%
Contingency (% of total cost)	2.0%	50%
Operating Assumptions		
Feed-in Tariff (LC / kWh)	5.39	
Duration of FIT (years)	20	
Tariff post FIT period (LC/kWh)	5.39	
FIT using Asset Base Methodology (LC/kWh)	5.39	
Annual CER volume (tCO2e / yr)	-	
O&M Cost ($000/Unit/yr)	775	
Spare parts, tools, & equipment ($000/MW/yr)	-	
O&M + Spares as a % of EPC,T/line, & Sub-stn	0.00%	
Refurbishment Cost (% of EPC)	0%	
Timing of Refurbishment (Year from COD)	-	
G&A Cost ($000/yr)	-	
Fuel Cost (switch for Biomass (1 = yes; 0 = no))	0	
Average Fuel Cost (Php/ton)	-	
Feed rate (kWh/ton)	-	
Average Fuel Consumption (tons/year)	-	
Average Unit Cost of Fuel (Php/kWh)	-	
Days receivable & payable	30	
VAT recovery %	100%	
Timing of VAT recovery (years after COD)	5	

Debt and Equity Assumptions	
Local/Foreign Capital Ratio:	
Local Capital Ratio	70%
Foreign Capital Ratio	30%
Debt:	
Local & Foreign Upfront and other financing fees	2.00%
Local & Foreign Commitment Fees	0.50%
Local All-in Interest Rate excluding tax	7.36%
Local Debt Payment Period (from end of grace pd)	10 Years
Foreign All-in Interest rate excluding tax	7.36%
Foreign Debt Payment Period (from end of grace pd)	10 Years
Local & Foreign Grace period from COD (months)	6
Local and Foreign Debt service reserve (months)	6
Debt ratio	70%
Total Local Debt ($000)	22,205
Total Foreign Debt ($000)	16,990
Total Debt Amount ($000)	$ 39,196
Equity:	
Equity ratio	30%
Equity Investment ($000)	$ 16,798
Cost of Equity (Onshore Equity IRR) - Nominal	12.77%
Cost of Equity (Onshore Equity IRR) - Real	12.77%
	1,277
WACC pre-tax	9.4%
WACC after-tax	8.5%
	847
Tax Assumptions	
Income tax holiday (years)	7
Income tax rate % (after ITH)	10%
Property tax (from COD)	1.5%
Property tax valuation rate (% of NBV)	80%
Local Business tax	1.0%
Government share (from COD)	1.0%
ER 1-94 contribution (Php/kWh)	0.01
Withholding tax on interest (Foreign Currency)	10%
Gross receipts tax on Interest (Local Currency)	5%
Economic Assumptions	
Base Foreign Exchange Rate (LC / USD) - 2009	55.5886
Forward Fixed Exchange Rate (2011)	55.5886
Base Local CPI - 2009	160.00
Annual Local CPI	0.0%
Annual US CPI	0.0%

Figure C.2: GEAR Model '*Asset Base FIT'* sheet

FIT Using Asset Base Methodology (Amounts in Php 000)

Discount Factor using Pre-tax WACC (%)	9.4%	*(8.47% after tax)*
Operating period (Years)	25	

	A	B	C	D	E	F	G	H = Sum of B to G	I	J = H / I
Year	**Asset Base + Working Capital + VAT**	**Annuity on Asset Base @ Pre-tax WACC**	**O&M Cost +Fuel Cost**	**G&A Cost**	**Local Taxes**	**Depreciation (CRF)**	**VAT Recovery and Other Adjustments**	**Total (Php 000)**	**NEO (MWh)**	**Tariff (Php/kWh)**
1	3,112,617	327,440	43,081	-	39,989	120,172	-	530,682	87,093	6.09
2	2,992,445	318,335	43,081	-	43,217	120,172	-	524,806	86,657	6.06
3	2,872,272	309,353	43,081	-	41,724	120,172	-	514,331	86,224	5.97
4	2,752,100	300,502	43,081	-	40,231	120,172	-	503,986	85,793	5.87
5	2,523,620	279,779	43,081	-	38,738	120,172	(108,308)	373,463	85,364	4.37
6	2,403,447	271,003	43,081	-	37,246	120,172	-	471,502	84,937	5.55
7	2,283,275	262,350	43,081	-	35,753	120,172	-	461,357	84,512	5.46
8	2,163,102	253,825	43,081	-	34,261	120,172	-	451,340	84,090	5.37
9	2,042,930	245,431	43,081	-	32,770	120,172	-	441,454	83,669	5.28
10	1,922,758	237,172	43,081	-	31,278	120,172	-	431,704	83,251	5.19
11	1,802,585	229,051	43,081	-	29,787	120,172	-	422,092	82,835	5.10
12	1,682,413	221,072	43,081	-	28,296	120,172	-	412,622	82,421	5.01
13	1,562,241	213,238	43,081	-	26,805	120,172	-	403,297	82,009	4.92
14	1,442,068	205,552	43,081	-	25,315	120,172	-	394,120	81,599	4.83
15	1,321,896	198,017	43,081	-	23,824	120,172	-	385,095	81,191	4.74
16	1,201,724	190,636	43,081	-	22,334	120,172	-	376,223	80,785	4.66
17	1,081,551	183,411	43,081	-	20,844	120,172	-	367,509	80,381	4.57
18	961,379	176,344	43,081	-	19,355	120,172	-	358,953	79,979	4.49
19	841,207	169,439	43,081	-	17,866	120,172	-	350,558	79,579	4.41
20	721,034	162,697	43,081	-	16,376	120,172	-	342,327	79,181	4.32
21	600,862	156,119	43,081	-	14,888	120,172	-	334,260	78,785	4.24
22	480,689	149,707	43,081	-	13,399	120,172	-	326,360	78,391	4.16
23	360,517	143,463	43,081	-	11,911	120,172	-	318,627	77,999	4.09
24	240,345	137,387	43,081	-	10,422	120,172	-	311,063	77,609	4.01
25	120,172	131,479	43,081	-	8,935	120,172	-	303,667	77,221	3.93
26	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
27	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
28	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
29	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
30	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
31	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
32	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	-	-	-
							NPV @ 9.4%	**4,217,556**	**797,053**	**5.29**

Levelized Tariff