Update of the

SOLAR

PHOTOVOLTAIC (PV) Roadmap for Singapore

TECHNICAL REPORT

UPDATE of the Solar Photovoltaic (PV) Roadmap for Singapore

Prepared for

NCCS, Strategy Group, Prime Minister's Office,
Economic Development Board (EDB),
Energy Market Authority (EMA) / National Energy Transformation Office (NETO)

by a

Consortium led by the Solar Energy Research Institute of Singapore (SERIS)

Lead Technical Officer:	Dr Thomas REINDL, SERIS (Lead Author)
Project Managers:	Dr KONG Xin, ERI@N Amit PATHARE, ERI@N
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<u>Front cover:</u> PV installation at Marina Barrage. Photo credit: SERIS

Co-Authors / Consortium Team Members in alphabetical order by organisation:

Solar Energy Research Institute of Singapore (SERIS), NUS:

Armin ABERLE, Shubham DUTTAGUPTA, KHOO Yong Sheng, Abhishek KUMAR, LIN Fen Serena, Celine PATON, Veronika SHABUNKO, Jai Prakash SINGH, TAN Congyi, ZHAN Yanqin, ZHANG Ji, ZHAO Shengnan

National University of Singapore (NUS)

Faculty of Engineering (FoE), Department of Electrical & Computer Engineering:
Dhivya Sampath KUMAR, Sanjib Kumar PANDA, Biplab SIKDAR, Dipti SRINIVASAN

Faculty of Science (FoS), Department of Chemistry:
Jason YEO Boon Siang

School of Design and Environment (SDE), Department of Architecture:
Patrick JANSSEN, Jack LEE Han Jie, LIN Zhuo Li

School of Design and Environment (SDE), Department of Building:
Stephen TAY En Rong

Energy Studies Institute:
Gautam JINDAL, KIM Jeong Won, Victor NIAN, Anthony OWEN, Ashish SINGH

Energy Research Institute @ NTU (ERI@N), including the Experimental Power Grid Centre (EPGC)

Annalisa BRUNO, CHAN Siew Hwa, DING Ovi Lian, Nelson GAO Zhi Yong, Yann GRYNBERG, Rupali KHANNA, Marcus KOH Leong Hai, KONG Xin, Subodh MHAISALKAR, Gyanesh Kumar PANDEY, Amit PATHARE, Alessandro ROMAGNOLI, Samson SHIH Shan Yao, Sundar THANGAVELU

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SP Group
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1 Executive Summary

Since the last Solar Photovoltaic (PV) Roadmap for Singapore was published in 2014, the PV sector has developed substantially in terms of the diversity of the underlying technologies, the economics, the size of the industry, and the modes of deployment. An update of the Solar PV Roadmap was therefore essential to guide the planning and development of the solar energy sector in Singapore. The project aimed to guide future research directions, government regulations and give a clear long-term perspective, which in turn would serve as a solid base for private sector investments, be it in research & development, manufacturing or system deployment.

Key outcomes of the study include:

1. A review of the projections of the 2014 PV Roadmap, which focused on providing the technical potential of solar energy in Singapore. This updated roadmap further filters the technical potential for actual usability of spaces and different adoption rates. The baseline scenario (BAS) was updated to be 1 GWp (2030) and 2.5 GWp (2050) while the accelerated scenario (ACC) was updated to be 2.5 GWp (2030) and 5 GWp (2050). The ACC scenario would lead to a 22% (2030) and 43% (2050) solar contribution to the electric power demand during mid-day and annual CO_2 emission savings of 1.6 (2030) and 3.4 (2050) million tonnes (Mt), respectively.

2. An update of the available areas for PV deployment, now based on the 3D model of the Singapore Land Authority (SLA), assessments of actual PV systems deployed and implementation considerations from various government agencies. Total net usable area has been reduced from the 2014 PV Roadmap of 45 km^2 to 36.8 km^2. This corresponds to the reduction in the technical potential of 10 GWp from the 2014 PV Roadmap to 8.6 GWp.

3. An initial grid impact assessment was carried out. No critical concerns are foreseen until 2030. For 2050, there is a need to further review and ensure grid resilience with greater solar deployment and intermittency in solar output caused by extreme weather events (i.e. sudden island-wide thunderstorms). This would call for mitigation measures such as solar forecasting, flexible conventional generation, energy storage systems and demand-side management where deemed necessary.

4. Updated “levelised cost of electricity” (LCOE) calculations, with a merit order list, ranking the various deployment options by their LCOE. In 2020, the lowest generation cost for PV in Singapore are calculated to be SGD 0.065/kWh for large-scale ground-mounted installations, SGD 0.076/kWh for MW-scale rooftop systems and SGD 0.097/kWh for large-scale floating PV installations on reservoirs. By 2030, the lowest generation cost is expected to be in the range of SGD 0.042-0.056/kWh, and by 2050 in the range of SGD 0.038-0.045/kWh. This compares to recent USEP prices (Uniform Singapore Energy Price) in the range of ~SGD 0.08-0.11/kWh.

5. New topics were introduced and discussed, such as:
   - Re-powering;
   - Recycling;
   - Renewable Energy Certificates (RECs); and
   - Importing of solar energy.

6. A list of RD&D topics has been derived, the outcomes of which could help to increase PV deployment and indicate to local industry where they could benefit from a technological leadership role. They include:
   - ultra-high efficiency solar technologies (e.g. heterojunction or tandem solar cells);
   - urban solar applications (e.g. mobile PV systems, building-integrated PV or off-shore floating PV).

7. A list of policy and regulatory recommendations was derived to support and foster local PV deployment. They include:
   - expanding PV adoption on government properties (e.g. mobile PV systems on vacant land, PV on existing infrastructure areas such as noise barriers);
   - encouraging more PV on buildings (e.g. higher incentives for rooftop and facade installations);
   - supporting financing of PV deployment (e.g. by partly sharing merchant risk through "contract for difference", CFD schemes);
   - adapting the regulatory landscape (e.g. capacity charges for the provision of power reserves or reduction in the dispatch cycle below the current 30 min).

2 Introduction

2.1 Background

The Solar Energy Research Institute of Singapore (SERIS) previously authored the "Solar PV Roadmap for Singapore" on behalf of the National Climate Change Secretariat (NCCS) and the National Research Foundation (NRF). The roadmap was based on available data in 2012 to 2013 and was eventually published in July 2014. It described how the solar PV market and deployment options could evolve in the timeframes up until 2020, 2030, with an outlook to 2050. It has been widely cited since as the standard reference for solar development in Singapore. In the absence of top-down targets, the roadmap adopted scenarios for the deployment of PV: a "baseline" (BAS) and an "accelerated" (ACC) scenario leading to different contributions of CO_2 emission reductions.

Since then, the Singapore government has taken progressive steps towards achieving a low-carbon future. One major initiative is the SolarNova Programme, which supports the country's goal to reach 350 MWp of installed solar power capacity by 2020. It also aims at aggregating demand through bulk tenders and support the establishment of a well-trained workforce, which will support the expected uptake in the private sector. Another programme was the Floating PV testbed at Tengeh reservoir. It has helped relevant agencies to understand the implications of floating solar on reservoirs and also brought Singapore at the forefront of research, development and deployment (RD&D) of floating solar globally.

Apart from achieving the carbon emission reduction targets pledged under the Paris Agreement, Singapore also needs to remain competitive and attractive for multi-national companies, which increasingly demand renewable energy supply for their operations; not restricted to only the RE100 companies.

Against this backdrop, the relevant government agencies (NCCS, EDB, EMA/NETO) commissioned this study to update the original PV Roadmap's assumptions and findings. The update aims to elaborate in detail what could be concrete targets for Singapore, the possible pathways, the cost to achieve them, and how Singapore's economy could eventually benefit from this.

The consortium that carried out the study consisted of (i) the National University of Singapore (NUS), representing the Solar Energy Research Institute of Singapore (SERIS), the Departments of Architecture (DOA), Building (DOB), Chemistry (DOC) and Electrical and Computer Engineering (ECE), as well as the Energy Studies Institute (ESI); and (ii) the Nanyang Technological University (NTU), representing the Energy Research Institute at NTU (ERI@N) and the Experimental Power Grid Centre (EPGC). As such, it combines the expertise of the most relevant institutions in Singapore, ranging from technology, deployment, grid integration to solar fuels, economic and policy.

The study was based on an in-depth understanding of the lessons learned in other parts of the world and a detailed assessment of those that were transferable or relevant to Singapore's context. The key objective was to identify areas where Singapore faces unique challenges and/or opportunities and provide a portfolio of solutions with different positioning in the cost-benefit matrix. This should allow decision-makers to balance the way forward and to steer future investments based on the expected outcomes and the associated risks.

2.2 Structure of the document

The Update of the PV Roadmap first summarises the recent developments in the global PV industry (Chapter 3). For Singapore, it gives an overview of the PV market and then revisits the projections from the 2014 PV Roadmap (Chapter 4).

The document then moves on to provide updates on the following topics from the original document:

- Space availability for PV deployment (section 5.1)
- Space utilisation (section 5.2)
- Increasing energy yield (section 5.3)
- Levelised cost of electricity LCOE) for solar PV in Singapore (section 5.4)
- Possible scenarios for PV deployment (section 5.5)
- PV grid integration (section 5.6)

The document also provides insights into new topics that arose since 2014:

- Re-powering (section 6.1)
- Recycling (section 6.2)
- Renewable Energy Certificates or RECs (section 6.3)
- Importing of solar energy (section 6.4)

In all sections, potential needs for RD&D, policy measures or regulatory actions are identified, which are summarised in Chapter 7.

2.3 Long-term considerations

This PV Roadmap has a time horizon until 2030, with an outlook until 2050. Despite the decadal timescale, the roadmap does not take into account long-term climate-related changes, which would have been beyond the scope of this update. Possible effects include, but may not be limited to:

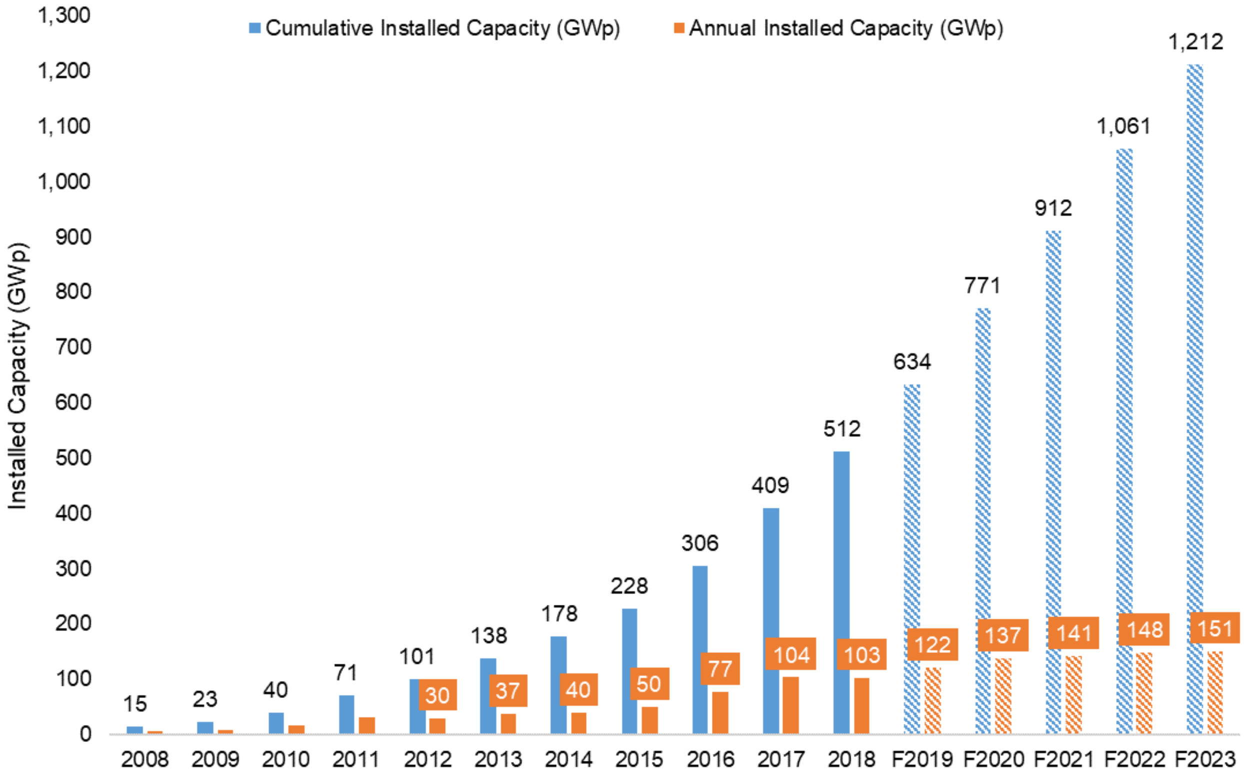
- Long-term temperature rises and the effect on PV efficiency;
- Long-term changes in humidity and cloud cover;
- Possible effects of changes in seasonal weather patterns (e.g. monsoons);
- Disruptive situations due to the increased frequency of extreme weather events.

For the last point, it is noted here that section 5.6.3.1 uses data from a rare typhoon event from 2017 to construct a worst case scenario in terms of ramp rate requirements of the power system due to a rapid increase in cloud cover and associated loss in solar power generation.

3 Global solar PV developments

At year-end 2018, the cumulative solar PV installed capacity globally surpassed the threshold of 500 GWp to reach 512 GWp. Annual 2018 deployment reached 103 GWp and was expected to be 122 GWp in 2019. The top five countries with the highest cumulative installed capacity at year-end 2018 were China (175 GWp), United States (63 GWp), Japan (56 GWp), Germany (46 GWp) and India (33 GWp) [1].

Annual solar PV installations are expected to increase steadily in the next five years, with forecasts varying quite significantly among the industry. SERIS estimates that annual capacity additions would gradually increase year-on-year to reach about 151 GWp in 2023 (Figure 3.1).



<u>Figure 3.1:</u> Historical and forecasted global PV installed capacity: 2008-2023. Source: SERIS based on data from: 2008-2018: IEA PVPS and 2019-2023: forecast (F) based on different sources (IHS, BNEF, SolarPower Europe, Wood Mackenzie, GCL and EnergyTrend).

The market growth is in line with a continuous reduction in cost for PV modules. This is partly due to advancements in technology and economies of scale, but also due to consolidation and over-capacities that arose from an even stronger anticipated growth and policy changes in certain markets (e.g. China[1]).

[1] The Chinese government had announced the "China 531" policy on May 31, 2018 to decrease and even remove, in certain instances, subsidies for solar PV installations in China.

Figure 3.2 shows the price reductions for PV modules over time. The “learning rate” from 1976 until 2018 was 23.2%. This means that average module sales prices have reduced by 23.2% for every doubling of cumulative PV shipments. In recent years (when taking data from 2006 until today), the learning rate is even higher at 39.8% [2].

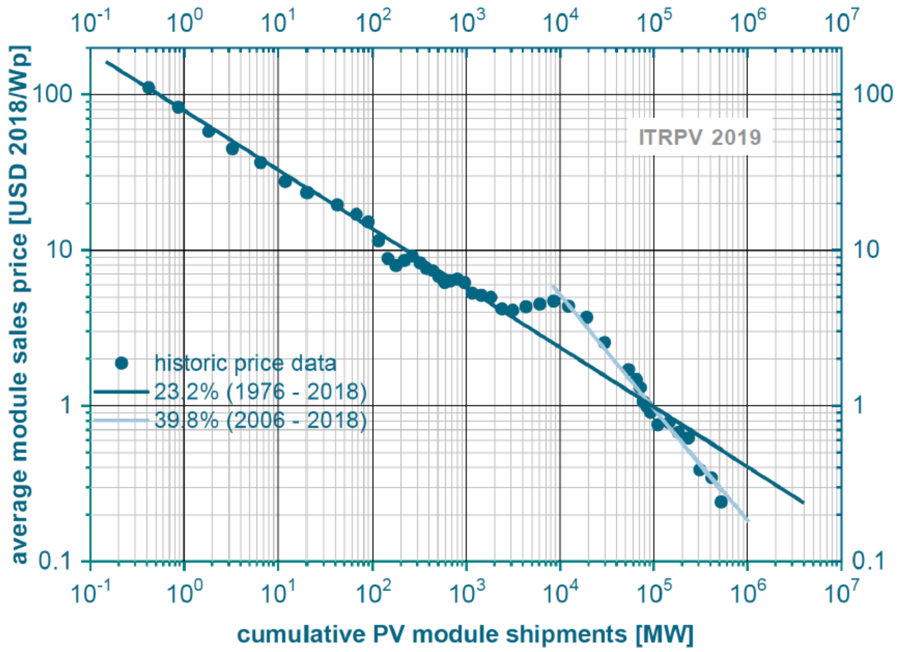


Figure 3.2: Learning curve for module price as a function of cumulative shipments. Source: ITRPV 2019.

PV module prices depend on the type and efficiency of module and cell technologies. On average, crystalline-Si PV module spot prices have decreased by more than 80% between 2010 and 2018 (see Figure 3.3).

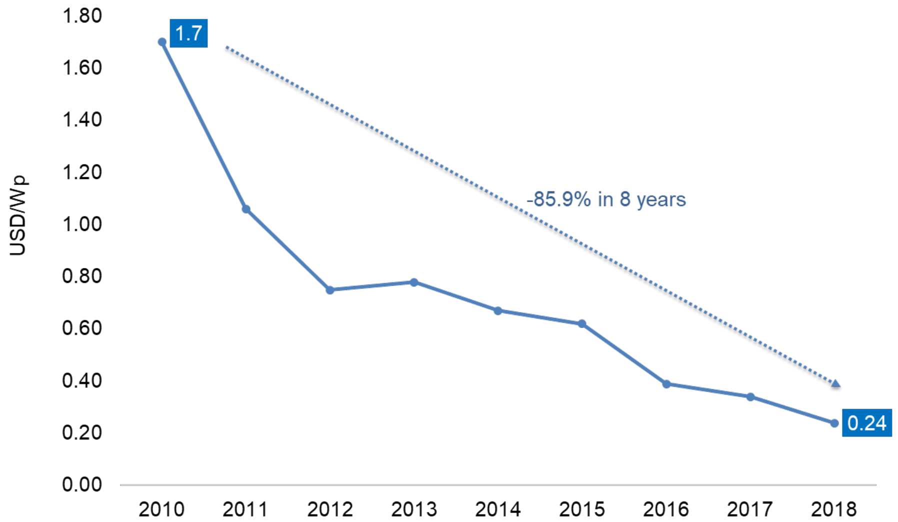


Figure 3.3: Average spot prices (USD 2018) for a representative mix of multi crystalline-Si and mono crystalline-Si wafer-based PV modules[1]: 2010 – 2018. Source: SERIS, based on ITRPV 2019 data.

[1] Average multi-Si cell efficiency = 19% and average mono-Si cell efficiency = 21.5%.

At end-2019, the average spot prices of low-cost multi-Si PV modules (280 Wp and below) were around USD 0.19-0.20/Wp, and for p-type mono-Si PERC PV modules (>280 Wp and below 310 Wp) around USD 0.22/Wp whilst higher efficiency modules (e.g. n-type mono-PERC) traded for around USD 0.28-0.32/Wp [3].

Solar PV module prices are expected to continue decreasing in the global market, although the rate of decline is difficult to predict, especially considering the fact that new higher-efficiency PV module technologies are being developed and progressively commercialised, generally at a premium during the first few years.

With a growing market and increasing volumes, Singapore will be able to benefit from this continuous reduction in PV module cost.

References for chapter 3:

[1] International Energy Agency (IEA). 2019. Task 1 Strategic PV Analysis and Outreach, Trends in Photovoltaic Applications 2019, Report IEA PVPS T1-36: 2019. ISBN 978-3-906042-91-6.
http://www.iea-pvps.org/index.php?id=trends

[2] International Technology Roadmap for Photovoltaic (ITRPV). March 2019. 2018 Results, 10th edition.
https://itrpv.vdma.org/

[3] PVinsights:
http://pvinsights.com/

4 Singapore solar PV developments

4.1 Singapore solar PV market

The cumulative installed capacity of solar PV installations in Singapore has grown steadily over the past five years, albeit at varying growth rates, as can be seen from Figure 4.1. Differences in growth rates are largely due to implementation phases of SolarNova tenders (demand aggregation by HDB and other government agencies).

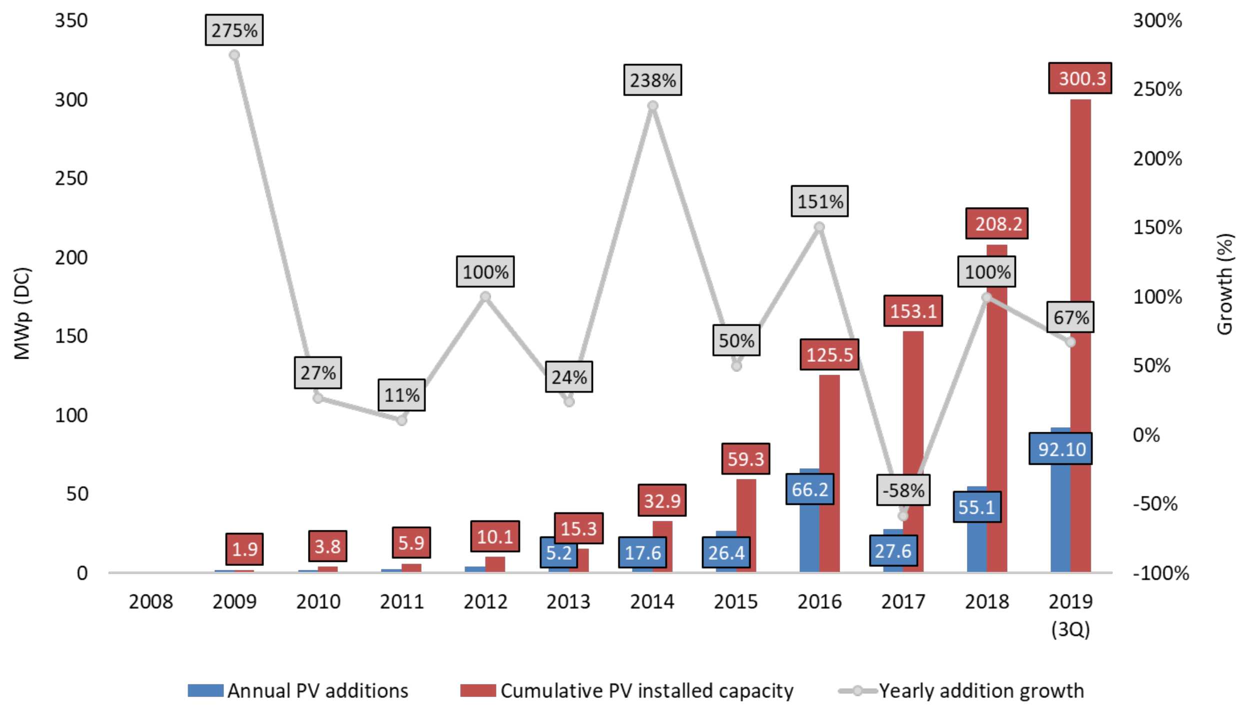


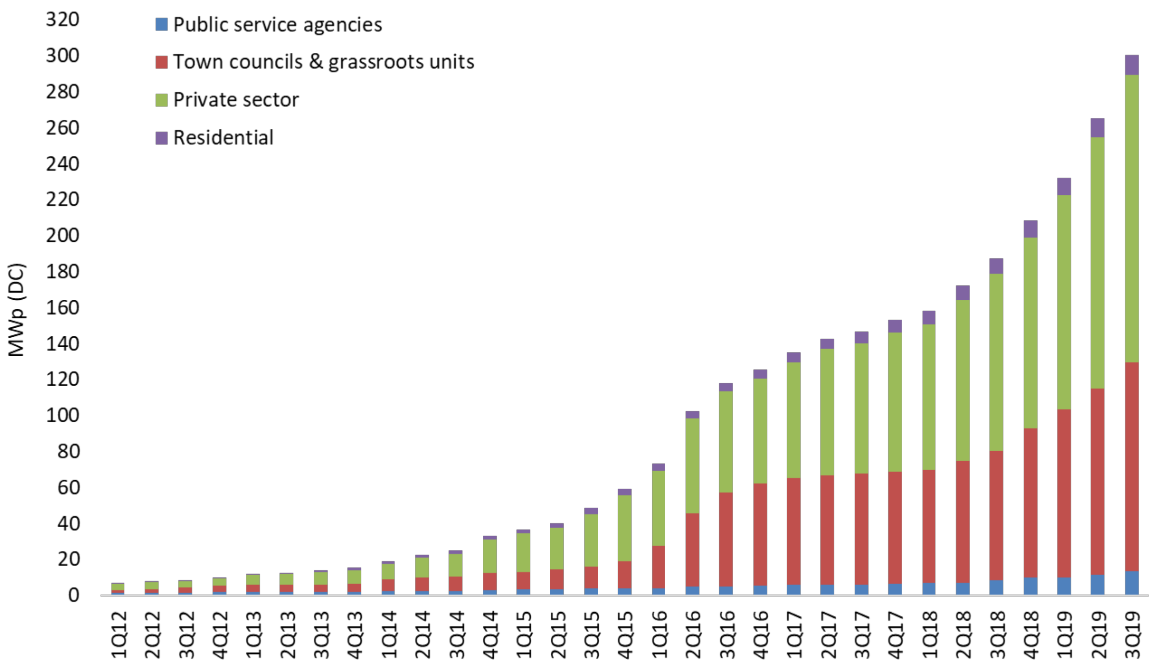
Figure 4.1: Annual solar PV installed capacity in Singapore: 2008 – 2019 (Q3). Source: SERIS, based on EMA and SP PowerGrid data.

Both the public and private sectors contribute almost equally to the growth of solar energy in Singapore (see Figure 4.2). For the public sector, this growth was largely driven by the SolarNova programme. Apart from self-owning a PV system, Solar PPAs[1], or “solar leasing” as it is more commonly known locally, are a popular form of agreement. Such contracts allow consumers and solar developers to enter into an arrangement that entitles the consumer to purchase solar electricity from the developer, usually at a discount from their prevailing contractual electricity prices. In return, the solar developer owns and maintains the solar energy system (which is installed on the consumer’s rooftop) for the term of the contract, which typically is around 20-25 years.

One advantage of this arrangement is that the consumer does not have to raise equity or take on substantial loans for the initial capital expenditure (capex) of the system. The second advantage is that the developer is responsible for operating and maintaining the system. This means that the consumer does not have to worry about equipment failure for which they may be inexperienced to deal with.

[1] PPAs = Power Purchase Agreements.

Another business model is to buy "renewable energy certificates" (RECs), which are discussed in more detail in section 6.3. RECs provide consumers another option to fulfil their renewable energy needs, especially if they do not have access to any or sufficient rooftop space.



<u>Figure 4.2:</u> Quarterly solar PV installations by user type in Singapore: 1Q 2012 – 3Q 2019. Source: SERIS, based on EMA and SP PowerGrid data.

Annex A provides an overview of the current policies and regulations for solar PV in Singapore.

4.2 Review of projections from the 2014 PV Roadmap

Based on the projections provided in the original roadmap, the team assessed that the following parameters were <u>*on target*</u> and the forward-looking trends are still in line with today's expectations:

- Solar cell efficiencies for high-end crystalline Silicon wafer-based technologies
- Area factors for high-efficiency crystalline Silicon wafer-based technologies

→ As a consequence, those projections did not see any corrections in this update.

The following parameter showed <u>*slight negative deviation*</u>:

- Actual energy yields of systems installed

→ As a consequence, one focus area should be the promotion of higher-yielding technologies in Singapore (see section 5.3.1).

The following parameters showed *substantial positive deviations*:

- PV module and system cost
- Levelised cost of electricity (LCOE)

→ Singapore is benefitting from the global reduction in module prices. Also, the growing domestic market leads to increasing experience of the local installation workforce and eventually lower cost of deployment. Section 5.4.1 provides an update of the current and projected LCOE for solar electricity in Singapore.

The following parameter showed *negative deviation*:

- Adoption rate of solar PV in Singapore

→ The uptake of solar PV was anticipated to occur much faster than it did in reality. By 2020, it was projected to have already 650 MWp in the baseline scenario (BAS) or even 900 MWp in the accelerated scenario (ACC). This compares to the actual installed capacity of 300 MWp as of Q3 2019, and an estimated ~400 MWp by end 2020.

One of the reasons for the overestimate was the very low oil prices in the 2016/17 timeframe, where the USEP price (Uniform Singapore Energy Price) was partly even below SGD 0.05/kWh, making solar installations unattractive for the private sector. Another reason was delays in some of the earlier phases of the SolarNova programme largely due to difficulties in obtaining financing (first time that project financing was required for solar PV in Singapore).

Both factors have since developed in a positive direction, but the updated deployment scenarios (see section 5.5) will reflect the lower base as of 2020.

5 UPDATES of the “PV Roadmap for Singapore”

This part of the document provides updates to the original roadmap across a wide range of topics, following the list in section 2.2.

5.1 Space availability for PV deployment

5.1.1 General considerations for PV deployment in Singapore

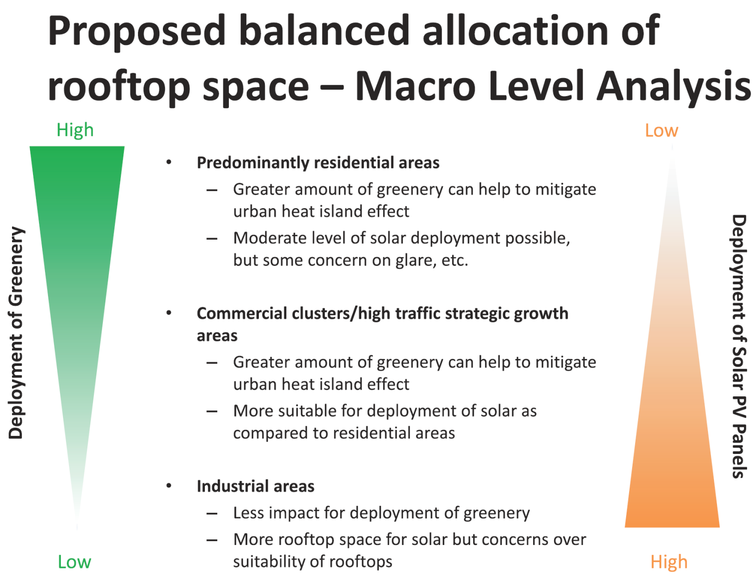
The technical potential derived here and summarised later in section 5.1.2.6, as well as the updated scenarios described in section 5.5, have to be balanced with many other considerations in urban planning and the future vision(s) of Singapore, in particular:

i. Greenery and the environment,
ii. Public acceptance, and
iii. Safety.

i. Greenery and the environment

Building upon 50 years of greening, Singapore aims to transform from a “biophilic City in a Garden” to a “City in Nature”. A concerted effort is being made to integrate nature and more intensive greening into the built environment. This is to reconnect people with nature for better health and well-being, as well as to strengthen the city’s resilience against the effects of urbanisation and climate change. In this regard, the deployment of PV should generally not be at the expense of greenery, green spaces and its biodiversity. This is a paradigm that would apply to ALL possible types of PV deployment described in this section.

For example, for the case of PV on buildings (rooftops, facades), there are plans for 200 ha of skyrise greenery by 2030, as part of the Sustainable Singapore Blueprint. Therefore, the following macro-level approach shall be adopted, which was the result of a joint taskforce for rooftop greenery and solar deployment by MND and MTI.



For Floating PV systems, there are concerns on deployment at the "Central Catchment Nature Reserve" (CCNR), the largest nature reserve in Singapore, and Kranji Reservoir, known to be a popular feeding ground for migratory birds. There are currently no long-term studies or global examples of the impacts of floating solar farms on the (i) microclimate of the area, (ii) vegetation, or (iii) fauna species that use the waterbody. As such, PV deployment will be prioritised in less sensitive waters such as the reservoirs in Tengeh, Bedok and Lower Seletar. The environmental impacts of floating PV deployment in these sites will be closely monitored, alongside additional reservoir sites being studied and considered for floating PV deployment.

The concerns regarding greenery and the environment have been reflected in the scenarios in section 5.5, by the fact that the suitable deployment areas have not been fully utilised, leaving ample room for greening programmes. It is also noted here that, for example for buildings, co-location of solar PV with greenery has potential benefits, as described in more detail in section 5.2.3.1. Such complimentary use of spaces is more likely in industrial developments, where it does not limit recreational uses, as compared to residential areas where green roofs tend to be more prevalent (i.e. roof gardens).

ii. Public acceptance

Thus far, the vast majority of PV installations in Singapore are on rooftops – and hence have hardly any visibility in the daily lives of Singaporeans. This will likely change when PV installations become more prevalent on facades in the form of building-added or -integrated PV (BAPV/BIPV); on reservoirs; and on structures over-arching carparks, walkways or land that are purposed for other uses.

Going forward, there also needs to be a discussion on public acceptance of the technology, especially as deployment progressively happens in more "visible" areas.

iii. Safety

Public safety is a key consideration when deploying PV in Singapore and needs to be adequately addressed. This applies, for example, to floating PV installations on reservoirs with recreational activities, as well as for PV on existing infrastructure areas such as roads or noise barriers. Another important factor is the fire safety of PV installations, particularly when deployed on, or attached to buildings.

5.1.2 Space assessment for PV deployment space availability

This section assesses possible deployment options for solar PV in Singapore over different land usages to evaluate the respective potentials. The study has identified different areas for solar PV deployment and sub-divided them into the five categories below. The assessments in this report are based on assumptions indicated in the respective paragraphs. Actual deployment potential will need to be subjected to detailed site studies, approval by relevant government authorities and adequate management of deployment impacts.

1. Rooftop PV,
2. Facades (for building-added and building-integrated PV, BAPV/BIPV),
3. Mobile-/land-based PV (temporary land use),
4. Floating PV (reservoirs, near-shore), and
5. Infrastructure PV (e.g. over-arching land, canals, roads, or PV noise barriers).

5.1.2.1 Rooftop PV

The assessment of available rooftop potential for solar PV deployment is based on the detailed 3D city model from the Singapore Land Authority (SLA), which was not available at the time of the original PV Roadmap, previously allowing for only a top-down approach. The 3D model of Singapore includes 158,000 buildings. After removing buildings with very small available surfaces (<10 m^2, which would be unusable for PV deployment), the entire solar potential study in this project covered approximately 132,000 buildings.

A specific process flow was developed for this project. The total surface area for all rooftops assessed was 98.7 million m^2, though not all of which are suitable for PV deployment. Therefore, the following filtering criteria have been applied:

a. Minimum irradiation (> 1500 kWh/m^2/year, equivalent to the "P90" irradiation[1])
b. Tilt angle (<15°, otherwise there will be losses in the in-plane irradiance)
c. Minimum continuous surface area (>130 m^2, otherwise not considered economical)
d. Surface utilisation factor:

   Depending on the building type, different utilisation factors were applied to identify the proportion of a given surface that is suitable for PV deployment (see Table 5.1). These factors were compiled according to detailed assessments of PV installations in practice and related studies on the physical characteristics of different building typologies. They take into account the reality that only parts of a roof surface can be used for PV deployment due to other uses. These include, for example, M&E equipment, water tanks, elevator shafts, and spaces reserved for tenants in commercial buildings.

   Comparing to the 2014 PV Roadmap, a substantial reduction in utilisation factors for HDB (0.33 from previously 0.5), commercial (0.2 from previously 0.6) and Others (0.3 from previously 0.6) was observed.

Table 5.1: Surface utilisation factors used in the assessment (from observations of actual PV system in Singapore)

Building type	Typical roof PV coverage ratio
HDB	0.33
Industrial	0.6
Commercial	0.2
Others	0.3

Figure 5.1 depicts the filtering process.

[1] The "P90" irradiation means that there is a 90% probability that the actual irradiation in the field is equivalent or higher.

It is noted here that this solar potential assessment was carried out on the existing building stock at the time of the 3D modelling in 2014. SLA is currently updating the 3D model with new LIDAR and photogrammetry data and hence an updated solar potential assessment could be generated, once the SLA model becomes available (in late 2020).

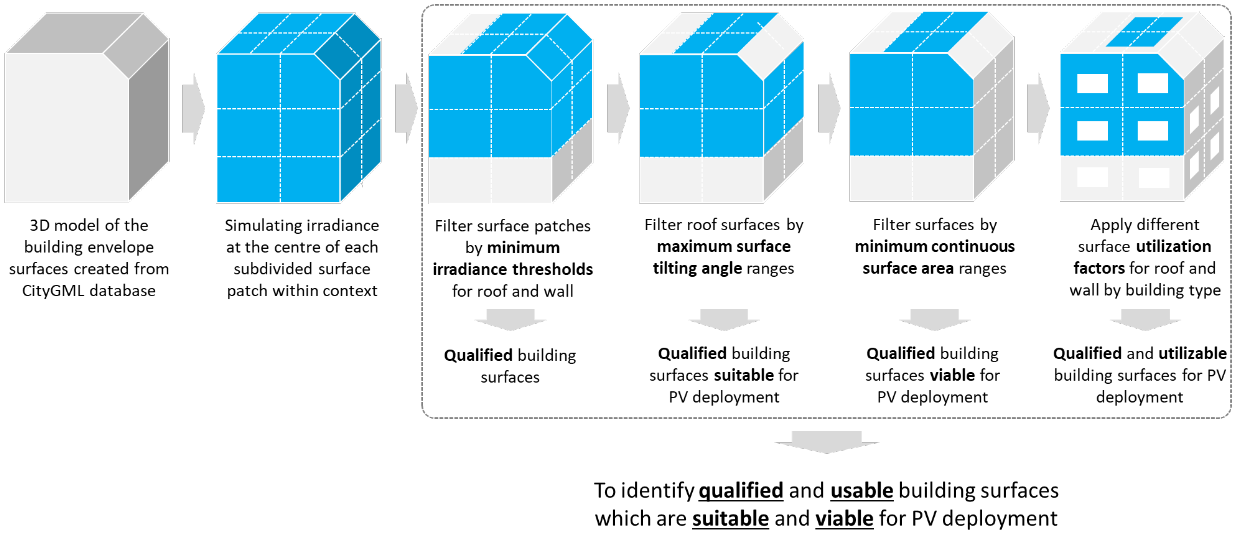


Figure 5.1: Process flow to identify net available building surface areas

The total resulting rooftop area for PV deployment was assessed to be 13.2 km^2. The summary in section 5.1.2.6 shows a break-down by different building types.

5.1.2.2 Façade areas

Similar to rooftops, the assessment of the façade potential for solar deployment is based on the detailed 3D city model from the Singapore Land Authority (SLA). This was not available at the time of the original PV Roadmap, which meant that only the top five floors of the assumed building stock were used in the calculations.

The assessment entails all façade areas suitable for PV deployment, independent of the degree of integration into the building, i.e. comprises of both, building-added PV (BAPV) and building-integrated (BIPV). Often in literature both options are generically referred to as "BIPV".

5.1.2.2.1 Façade areas on existing buildings

The total surface area for all facades assessed is 214 million m^2, though not all of which are suitable for PV deployment. Therefore, the following filtering criteria have been applied:

a. Minimum irradiation thresholds (> 750 kWh/m^2/yr and > 500 kWh/m^2/yr)
b. Minimum continuous surface area (>130 m^2, otherwise not considered economical)
c. Window-to-wall ratio (WWR):

The window-to-wall ratio is equivalent to the "surface utilisation factor" on rooftops. In the absence of a 3D model with "LOD 3" (level of detail) where the façade features and surface properties would be described, different WWRs were applied for different building types and orientations to identify the proportion of a given surface that is suitable for PV deployment (see Table 5.2). They are based on practical experience and/or the WWR prescribed in the Green Mark certification guidelines.

Table 5.2: Window-to-wall ratios used in the assessment (practical experience and/or the WWR prescribed in the Green Mark certification guidelines).

Building type		Window-to-wall ratio (WWR)
HDB		0.4
Industrial		0.2
Commercial	(East or West facing facades)	0.28
	(North or South facing facades)	0.4
Others		0.4

In total, the filtered facade areas add up to 7.88 km^2. Section 5.4.2 discusses the life-cycle cost (LCC) for BIPV systems, including the sensitivity to the irradiation value. It is noted here that a relaxation of the threshold from 750 $kWh/m^2/year$ (used above) to 500 $kWh/m^2/year$ would lead to a 7-fold increase in possible surface areas, see also section 5.1.2.6.

It is noted that harvesting the technical potential of the existing buildings for BIPV requires retrofit measures, which are most economically carried out at the point of major A&A (Addition & Alteration) works, during façade renovations (e.g. change/repair of cladding) or upgrading of the façade (e.g. to comply with latest fire regulations).

5.1.2.2.2 Façade areas for BAPV/BIPV on new buildings

It is arguably easier to deploy BAPV/BIPV on new buildings versus existing buildings, as the technology can be integrated from the beginning of the design and planning process. This allows for more design options and for the installation to be more cost-effective, as it would not add significantly more cost than a conventional façade cladding, for example.

In the absence of data on how many new buildings are erected every year in Singapore, a conservative estimate of 100 was assumed for the potential assessment (which excludes re-development of existing buildings).

For the case of a rather small installed capacity of 100 kWp per new building, which would require approximately 650 m^2 each, the total net surface area potential would be 1.95 km^2 until 2050. This is likely the lower end of the potential for new buildings.

It is noted that once the updated 3D model from SLA is available (later in 2020), it is possible to generate a gap analysis between the 2014 and the 2019 data in order to assess the average annual addition of buildings in Singapore.

5.1.2.3 Mobile-/land-based PV

Mobile/land-based PV systems refer to the use of land, which has been earmarked for development or reserved for certain purposes, for the temporary deployment of solar PV. This is possible if the actual use of the land is not needed in the short- to medium-term, and provided that the installations are made in a way that they can be easily removed within a certain period of time and in a cost-effective manner. This concept had been described in the original PV Roadmap and JTC has already taken the lead through its "SolarLand" programme, whereby operators get to bid for a plot of land, with the knowledge that they might have to re-deploy the PV system to another location during its economic life. Figure 5.2. shows the first such deployment of 5 MWp on Jurong Island. By 2030, JTC aims to expand the SolarLand programme to ~100 MWp of solar capacity.

Figure 5.2: Aerial view of the 5 MWp system deployed by Terrenus Energy on Jurong Island under JTC's SolarLand programme

5.1.2.3.1 Assessment of available land plots on islands

There are as many as sixty-three offshore islands and islets around Singapore, however, only islands with a potential to be connected to the electricity grid on the mainland were assessed in this study. Smaller offshore islets were not considered in the analysis, as it would likely not be economically viable to lay undersea transmission cables for relatively small areas available for solar deployment.

As such, two islands were identified and analysed in more detail for large-scale PV deployment: Jurong Island and Pulau Semakau.

Jurong Island:

Jurong Island was assessed to be suitable for grid-connected solar PV installations of a notable size. For context, Jurong Island is an amalgamation of seven smaller islands and now serves as Singapore's petrochemical hub. In addition to existing rooftop PV systems on the island, there is also the fore-mentioned 5 MWp ground-mounted system under the JTC SolarLand programme. Analysis of satellite imagery suggests that there are vacant spaces on Jurong Island that could potentially be used for mobile-/land-based deployments.

Jurong Island also has a sizeable conventional power generation base and strong electric power connections, which could be leveraged for the export of the generated solar electricity back to the main island.

It is unlikely that all of these spaces will remain vacant for the next twenty or more years due to competing land uses. The usage of these vacant spaces would also have to be de-conflicted with the relevant stakeholders to minimise the impact on planned or surrounding developments.

URA and JTC are still studying the actual amount of vacant state land available for mobile-/land-based PV deployments. Based on the study of satellite pictures, the technical potential has been assessed to be ~5 km^2.

Pulau Semakau:

As part of the REIDS testbed (Renewable Energy Integration Demonstrator Singapore), Semakau is home to a 1.5 MWp solar PV installation. At present, it is not connected to the main island. Developers seeking to build a PV system on Pulau Semakau for the purpose of exporting electricity to the main grid would have to build an undersea transmission cable of at least 1.5 km to the closest grid connection point at Pulau Bukom. Assuming this can be accomplished, Pulau Semakau could add approximately 0.85 km^2 of usable land for PV deployment by 2030. This could be followed by another 0.85 km^2 by 2050, as the ash deposition area grows. It is noted here that any potential PV deployment should avoid the biodiversity-rich areas in and around Pulau Semakau.

5.1.2.3.2 Assessment of available land plots on the main island

Similar to the above, an initial assessment of potential vacant land areas on Singapore's main island was carried out by using the dataset "SLA vacant State land and properties", which captures vacant land plots in Singapore until they are leased out for interim uses, excluding those managed by SLA appointed agents.

It is noted here that JTC manages a large set of land areas that are reserved for industrial development, which is not captured in the dataset. Hence the results below should be taken as the lower boundary of possible deployment areas.

In assessing whether spaces could be utilised for solar deployment, the following areas were excluded from the list due to considerations regarding public acceptance, conflicting interests or economic viability:

- Neighbourhood fields
- Forested / nature areas
- Unsuitable sundry areas
- Newly reclaimed land

It was assessed from the analysis of satellite images that the possible areas for mobile-/land-based PV deployment on the main island could add up to ~0.38 km^2. As mentioned above, this analysis is not exhaustive and does not include the industrial land managed by JTC.

5.1.2.4 Floating PV

Floating PV refers to the deployment of solar PV systems on water bodies, be it fresh water reservoirs or "off-shore" in marine waters. For the latter, given the limited sea space in Singapore, this analysis focused on "near-shore" applications within its territorial waters.

5.1.2.4.1 Floating PV on reservoirs

Through government initiatives like the "Floating PV testbed" at Tengeh Reservoir, Singapore is at the forefront of global RD&D when it comes to deploying PV systems on in-land water bodies. Apart from smaller installations on Bedok, Lower Seletar and Upper Peirce reservoirs, the main project at the moment is a 60 MWp on Tengeh Reservoir, which will be operational by 2021.

While the total surface area of water bodies in Singapore is about 6%, only a fraction of that can be used for Floating PV deployment due to various restrictions. These range from environmental concerns to competing uses such as for recreational and military-training purposes.

An exercise was conducted to collect inputs from various agencies to assess and determine the theoretical maximum deployable solar PV capacity on in-land water bodies. This turned out to be in the range of ~4 km^2 of gross area. After discounting the water areas earmarked for maintenance floats and safety buoys, this translates to a net PV area of about 2.5 km^2, as assessed by the consortium (this is the area that would be covered by PV panels only).

5.1.2.4.2 Floating PV in maritime waters

As part of this PV Roadmap Update, various discussions were held with relevant authorities overseeing the sea spaces surrounding Singapore. These included agencies like MPA, URA, NParks and parts of the "GeoSpace Sea" group.

It became clear that the sea space is already very congested and will likely remain so in the future, with the new harbour in Tuas having almost double the capacity. Apart from floating PV, many other possible "floating structures" had been proposed in the past, such as floating data centres, floating hotels and even floating farms.

This study therefore focused on the so-called "dead sea spaces", which are defined as areas in maritime waters that are not usable for other purposes and/or are already affected by the main (mostly industrial) use of the area. A typical example are waters behind a jetty, such as those located behind the anchoring points for oil tankers. The resulting area between the coastline and the jetty is then not of much use for other maritime purposes. As such sites also may have biodiversity, they will have to be assessed for environmental and biodiversity impacts.

A high-level assessment around the coastal waters of Singapore revealed that there are ~2.12 km^2 of such near-shore dead sea spaces.

5.1.2.5 Infrastructure PV

Apart from the temporary use of vacant land, there are also opportunities for Singapore to utilise existing infrastructures by combining them with solar PV systems, while not interfering with the original use of the land. This section assesses the possibility for dual uses of infrastructure areas, in decreasing priority:

- Existing land
- PV noise barriers
- Flood canals
- Existing roads

<u>Existing land:</u>
Generally, existing land uses (e.g. certain farming areas or "hard surfaces" like un-shaded parking lots) can be expanded by going into the third dimension through over-building the land with solar PV systems. This was conservatively assessed from the analysis of satellite data to be approximately ~2.5 km^2.

<u>PV noise barriers:</u>
PV noise barriers have been deployed in several European countries such as Switzerland, Germany and the Netherlands.

In Singapore, around 27 km of noise barriers are expected to be installed across the island's rail network[1]. There is a wide range of considerations that would need to be addressed for PV noise barriers. These include: noise reduction properties of PV modules; potential glare impacts on both traffic participants and residents; additional fire/electrical risks and impact on maintenance works on MRT viaducts.

It is noted here that LTA also works with NParks to green up and "soften" the noise barriers, i.e. increasing their noise absorption properties (as compared to noise reflection for hard surfaces). Similar to the co-location of PV and greenery on rooftops, there could be opportunities to develop joint deployment concepts for advanced noise barriers.

A conservative assessment based on an exemplary 5 m high noise barrier would lead to a theoretical surface area of ~1 km^2 for noise barriers.

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[1] The Straits Times, 15 Dec 2018 (*https://www.straitstimes.com/singapore/tender-called-for-3rd-phase-of-railway-noise-barrier-works*).

Flood canals:
As a tropical island, Singapore experiences heavy thunderstorms and torrential rainfalls from time to time. The water masses coming down on the island at those times need to be collected and drained off quickly to avoid flooding of roads, residential, industrial and commercial areas. For that, Singapore has built an island-wide network of drainage canals, which largely vary in width and depth, but in-principle could be overbuilt with PV installations.

From available databases, the total surface area of canals in Singapore is ~2.5 km^2, out of which only a small fraction (assumed to be 10%, i.e. 0.25 km^2) will likely be acceptable to agencies and the general public for the deployment of solar PV systems.

It is noted here that many of the canals may have developed substantial bioactivity over the years. NParks and PUB are also engaged in converting parts of flood canals into greenery and/or other recreational activities. Examples are Bishan/AMK park and the recently announced upgrade of the Bukit Timah canal to become part of the Bukit Timah-Rochor Green Corridor.

In addition, there are huge variations in water levels and in the widths of drainage canals. There are also concerns that PV deployment would significantly affect PUB's access to drainage canals for maintenance, hence making this deployment option rather difficult to implement.

Existing roads:
Innovative structures can be used to over-arch roads in a way that the traffic underneath would not be adversely affected (see illustration in Figure 5.3). In order to keep this within economic limits, it is most suitable for 2- to 6-lane roads. Wider roads (including highways) would require very heavy structures, which would then increase the capex substantially. Further assessment on the size and safety of the supporting structure would need to be carried out, for example in the event of a vehicle collision with the support structure.

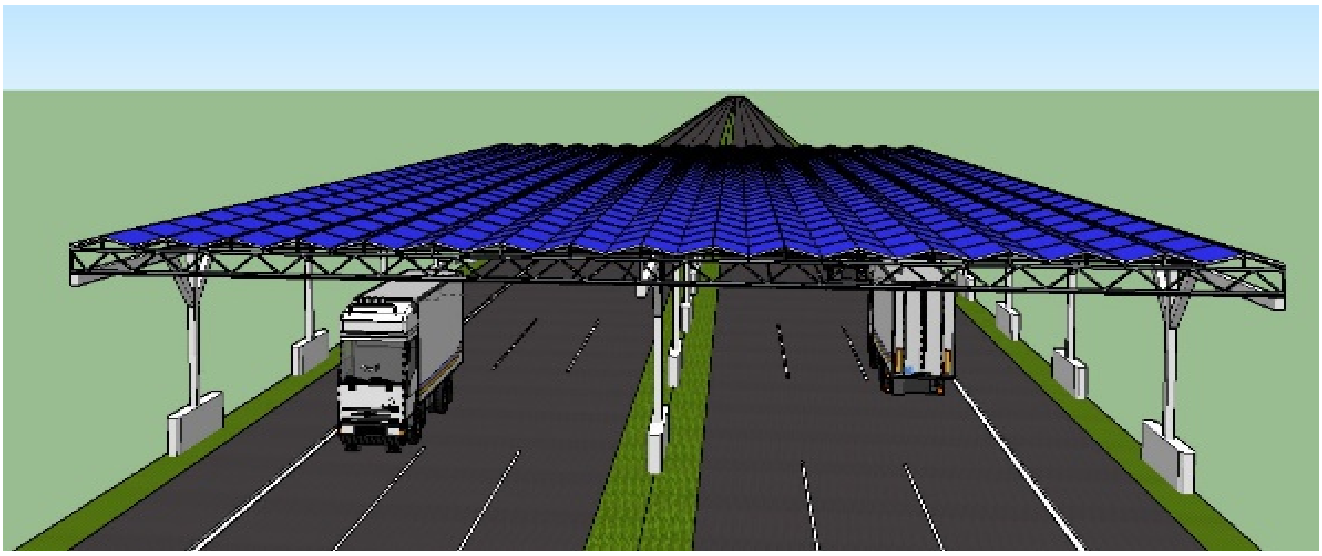

Figure 5.3: Artist impression of a retractable system over-arching existing roads. Source: iWorks AG.

Any over-building of roads for solar deployment has to be contained within the "road reserve" (RR) and not take up additional land beyond the road reserve. Their construction and structures must also not negatively impact existing road furniture, plantings, signs and underground services or result in any need to increase the safeguarded RR to support them.

For an initial assessment, the following methodology was applied:

- Only so-called “arterial roads” (both minor and major) were considered;
- Main focus was on the Western industrial areas where there is generally less vegetation that possibly could cast shadows on the PV installation;
- The estimated length of arterial roads in that area is approx. 100 km. Taking an average width of 12 m for a 4-lane road, this would add-up to 1.2 km^2, out of which only one third (i.e. 0.4 km^2) has been taken into account due to restrictions that are foreseen during planning and implementation.

It is noted here that this concept would need to overcome the challenges listed below and would need to be evaluated in much greater detail, in close collaboration of the relevant agencies, particularly with MOT, LTA, SCDF and NParks (e.g. for the proposed planting verge along the roadside in industrial areas, which would obviously affect the areas available for such concept):

- Grid interconnection;
- Visual impact on drivers from the change in brightness when driving in and out of such structures, and whether additional lighting fixtures will be required to supplement the lighting level;
- Integration of the existing street lighting system as the lights might be installed up to 13 m high along major roads. Furthermore, in the event of inclement weather during the early morning or late evening, the streetlights may need to be turned on earlier in the evening and be kept turned on for a longer duration in the early morning. This could incur increased utility costs;
- Fire-fighting access (e.g. exit staircase, clearance space) will need to be provided for these structures in the event of a fire, along with other fire safety requirements (e.g. fire rated separation for services like lightings or sprinklers installed underneath these structures).

5.1.2.6 Summary of possible areas for PV deployment

Based on the assessment in this section, Table 5.3 summarises the possible net usable areas for PV deployment in Singapore. This data is also used as the basis for the later scenario updates in section 5.5.

Table 5.3: Summary of net usable areas for PV deployment in Singapore.

Deployment type	Sub-category	Total net usable area [‘000 m^2]	Remarks
Roof-top[1)]	HDB	2,225	
	Industrial	8,056	
	Commercial	1,656	
	Others	1,284	Including (amongst others): Non-HDB residential and educational institutions.
		13,221	
Facades	Retrofit[1)]	7,877	Using irradiation >750 kWh/m^2/yr; would be 56 km^2 for >500 kWh/ m^2/yr
	New buildings	1,950	Until 2050, based on 100 new buildings per year
		9,827	
Mobile-/land-based PV		5,000	Conservatively using only 70% of the available land areas on Jurong Island (5 km^2), Pulau Semakau (0.85+0.85 km^2) and the main island (0.38 km^2)
		5,000	
Floating PV		4,616	Inland reservoirs and “dead sea” spaces
		4,616	
Infrastructure PV	Existing land	4,150	Potential areas for PV noise barriers and for over-building existing land, canals and roads.
		4,150	
TOTAL		**36.8k**	

1) Based on existing building stock in 2014, and 3D model assessment.

This area is ~18% smaller than the 45 km^2 estimated in the 2014 PV Roadmap. The main reduction comes from the significantly smaller space utilisation observed in real-world PV installations since 2014, particularly for HDB and commercial rooftops. This is partly compensated though by the identification of larger possible land-based areas, increased potential for facades and infrastructure areas.

If all areas in Table 5.3 would be fully utilised, the technical potential for PV in Singapore by 2050 would be 8.6 GWp (compared to 10 GWp in the 2014 Roadmap).

5.2 Space utilisation

Maximising the limited space for solar PV deployment in Singapore also means that technologies should be employed that promise highest possible use of the available areas. Today, a standard 60-cell solar module (multi-crystalline p-type) of 1 m x 1.6 m in size has around 280 Wp. At the same time, REC Solar from Singapore launched their latest “Alpha” series in 2019, which is based on hetero-junction technology, but delivers up to 380 Wp on the same module area. Such ultra-high efficiency technologies come at a price premium, but eventually make the BOS components (balance of systems = all non-module cost of a PV installation) relatively less expensive, as for the same amount of support structure, cabling and manpower, there is 40% more power output.

Based on LCOE analyses, the lifecycle cost of ultra-high efficiency technologies are about the same as standard mass-produced modules, despite the higher initial capex. At the same time, however, the area efficiency and hence the space utilisation is substantially higher, as can be seen from Figure 5.4 (note: cost assumptions for high-efficiency technologies are based on mass production; current market prices are higher due to limited availability). This should be the way forward for space-constrained Singapore.

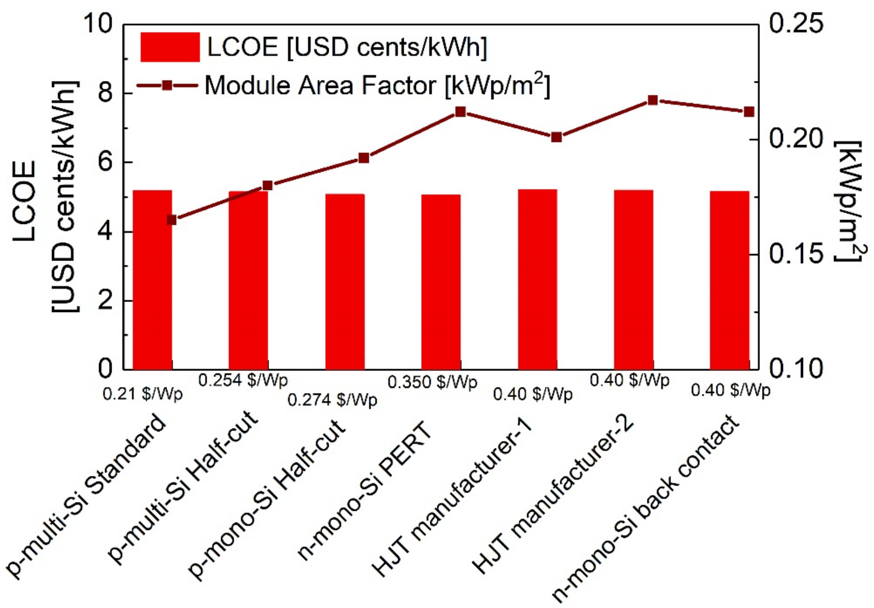

Figure 5.4: LCOE for various solar cell technologies with different efficiencies (expressed as “module area factor”) and cost. Source: SERIS in-house LCOE model.

The following sections will go into detail as to which solar technologies would be seen as favourable for further development of the solar PV market in Singapore.

In addition, this chapter will also highlight RD&D needs for novel deployment options that are beneficial for Singapore.

5.2.1 High to ultra-high efficiency solar technologies

5.2.1.1 Crystalline Silicon based technologies

In the past five years, the silicon wafer-based solar cell industry has seen new advancements in all areas of technology, from silicon material (shift towards mono-Si), process technology (diamond wire wafer sawing), cell architectures (passivated contact cells) to bifacial structures. Near- and long-term trends in industrial solar cells clearly indicate a move towards high-efficiency technologies at no major increase in manufacturing cost (once mass produced).

As shown above, it is beneficial for maximising space utilisation to use ultra-high efficiency technologies, even if they come at a price premium. Very promising architectures are hetero-junction solar cells (HET) and all-back contact structures (ABC), which can also be combined. In addition to better space utilisation, these technologies also have a higher energy yield in Singapore's hot climate conditions (see section 5.3.1).

It is noted here that the current major players in both technology fields are headquartered in Singapore: REC Solar for hetero-junction technology and, going forward, Maxeon Solar (former SunPower) for ABC.

5.2.1.2 Future perovskites and tandem technologies

<u>Perovskites</u>

Photovoltaic (PV) technologies are divided into two big categories: wafer-based and thin-film solar cells. Wafer-based PV includes crystalline silicon (c-Si), which dominate with ~95% market share, with the only notable thin-film technology being Cadmium-Telluride (CdTe), marketed by First Solar.

Thin-film solar cells are able to absorb light 10-100 times more efficiently than silicon, allowing the use of thin layers of just a few nanometers or microns in thickness; however, they often suffer from other challenges compared to c-Si technology (e.g. efficiency or long-term stability). One rather new category of thin-films are metal-halide perovskites, which have reached efficiencies as high as 24% just within a decade of research. They have the potential to allow for flexibility in device processing and could be deposited on inexpensive substrates. Today, they are still in the R&D stage, with small cell sizes and short lifetimes, but the potential is promising. Therefore, a number of institutes and companies are working on their improvement, including teams in Singapore.

<u>Tandems</u>

Tandems are solar cells with multiple p-n junctions made of materials with different bandgaps, hence they are sometimes also called multi-junction solar cells. As materials with different bandgaps absorb different parts of the solar irradiance spectrum, higher energy conversion efficiencies can be realised by optimally combining different solar cell materials (see Figure 5.5).

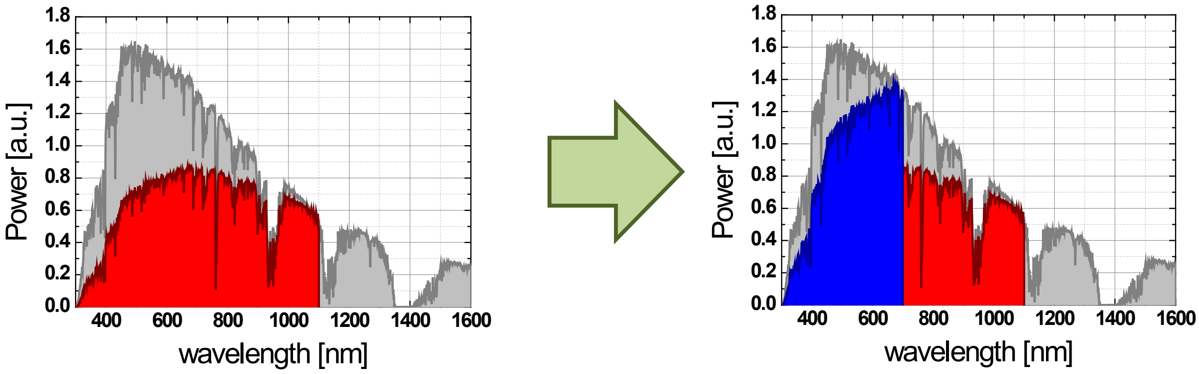

Figure 5.5: Generic principle of better harvesting the solar spectrum through double junction solar cells (tandems)

Many leading c-Si manufacturers have listed tandem solar cells in their technology roadmaps in order to overcome the efficiency limit of single junction solar cells and to move beyond the 30% efficiency threshold. In Singapore, various groups work on “Perovskite-on-Silicon” tandem solar cells, together with industry partners.

5.2.2 Area factor for PV systems

The “area factor” for deployment of PV systems on net usable areas describes how much PV capacity (in kWp/m^2) can be installed without causing shading from one row of modules to the other, and after considering a small gap between rows to enable access for maintenance works. Figure 5.6 visualises the approach. It is also noted here that in many rooftop projects the two modules are often installed in an inverted V shape arrangement (so-called “dual-pitch”). This would even allow for a slightly higher space utilisation.

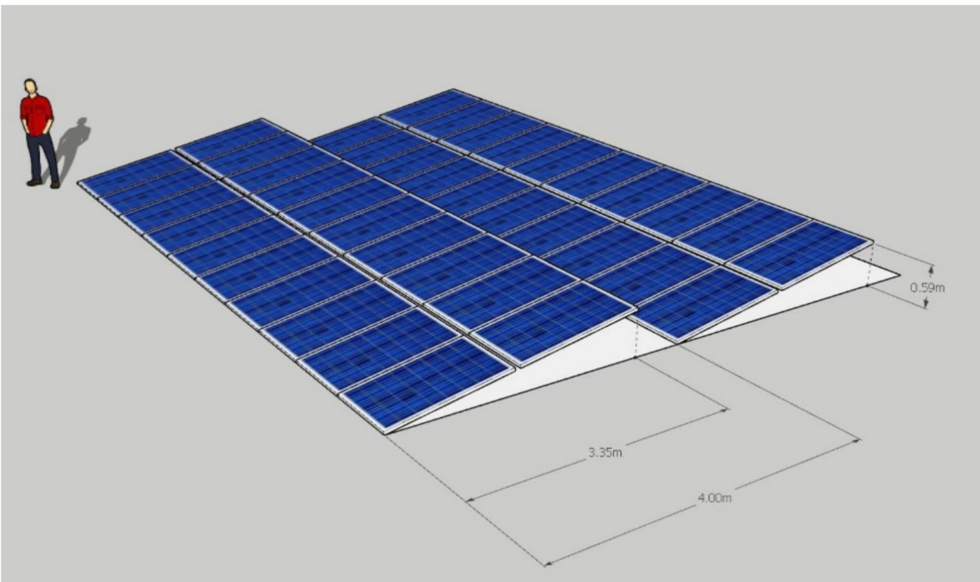

Figure 5.6: Two-row configuration of a solar array used for deriving the “area factor”. The gap between rows is sufficiently large to avoid row-to-row shading and to enable maintenance access.

Using today's standard module efficiencies, i.e. 280 Wp, and applying the 4 m distance between arrays, the resulting area factor is 0.14 kWp/m^2.

In case of higher-efficiency modules, e.g. 330 Wp (for REC's n-type mono-Si technology), this area factor goes up to 0.165 kWp/m^2, and when taking the recently released industry-leading top module from REC, the new "Alpha series" with 380 Wp, it's 0.19 kWp/m^2 – the value which was projected for 2020 under the BAS scenario in the 2014 PV Roadmap, and slightly below the ACC scenario (0.2 kWp/m^2).

The area factor projections for "high-efficiency PV systems" for optimal space utilisation are listed in Table 5.4.

<u>Table 5.4:</u> Projected "area factors" for PV systems under the two scenarios, BAS and ACC (see also section 5.5), when using high-efficiency solar cell technologies.

Future area factors in [kW$_p$/m^2] for high efficiency PV systems			
Year	**2020**	**2030**	**2050**
BAS	0.19	0.21	0.22
ACC	0.20	0.25	0.30

This is equivalent to the following PV module power and solar cell efficiency values:

0.25 kWp/m^2:
PV module power: ~500 Wp
Solar cell efficiency: ~28%

0.30 kWp/m^2:
PV module power: ~600 Wp
Solar cell efficiency: ~35%

These values will require tandem solar cell structures, which are expected to be commercially available in the projected efficiency levels at the respective time frames.

5.2.3 Novel PV applications

Apart from industry-leading solar cell and module technologies, there are also opportunities for application and development of novel, cost-effective solutions for the various PV deployment options that were described in section 5.1.2. Only then will it be possible to maximise the solar potential and use the home market to develop technologies, test them and eventually commercialise them also in other urban settlements overseas that want to go solar on a large scale. This would underpin Singapore's aspired leadership position in "Urban Solar".

5.2.3.1 Rooftop PV

<u>Rooftops:</u>

In various discussions with agencies and industry players, it was highlighted that there was a lack of standardised rooftop systems in the market. To bring down costs and to allow for faster and less labour-intense deployment, it would be advantageous to develop replicable blocks of system components, which can be manufactured in larger quantities at higher economies of scale.

There are very few standardised roof-top systems in the market. Hence, this could be a great opportunity for Singapore to take the lead in developing such systems for urban solar applications.

In addition, standardised structures could enable future technology upgrades (“re-powering”, see section 6.1) and also be beneficial for reducing wastage (“recycling”, see section 6.2).

<u>Co-location of roof-top PV with greenery:</u>

Co-locating solar PV systems with greenery has been tested in many countries around the world, with most of the advanced work carried out in Europe. It is understood that there is a positive energy yield impact from the combined deployment of PV and greenery. One of the European studies, “Biosolar Roofs”, a collaboration among research partners in six countries, also assessed the biodiversity for such co-located deployment (see Figure 5.7). It remains highly climate-specific though, as to which greenery works best together with the solar panels.

<u>Figure 5.7:</u> Example of co-location of PV installation with extensive green roof. Source: “Biosolar Roofs” project.

For the case of Singapore, NUS had reported on the benefits of co-locating PV with greenery already in 2014. Installing a small solar panel on top of some shrubs led to a measurable, about 2% increase in annual energy yield due to the cooling effect from the evapotranspiration of the plants (combined effect of plant activity and evaporation from the water used for irrigation).

In recent years, BCA, NParks and NEA, in collaboration with NUS, evolved this concept further. For example, tests were undertaken to ascertain which plants would be suitable for co-locating PV with greenery in Singapore and a larger testbed is in preparation.
In general, PV can be co-located with both types of greenery: extensive and intensive. For extensive greenery, it is mostly shrubs and grass types, which can deal with the lower irradiance levels underneath the solar modules, as well as the occasionally higher irradiance levels between individual modules and between rows of the PV array.

For intensive greenery, i.e. roof gardens, the PV modules can be elevated and over-arch the plant area, to act as shading device above the roof garden. As such, plants underneath would need to be able to deal with partly-shaded irradiance conditions. The structural weight of an intensive greenery with PV will be higher than for an extensive greenery. Depending on the merits of the co-location proposal, the area covered by solar panels co-located with greenery could be counted towards URA's LUSH programme (Landscaping for Urban Spaces and High-Rises) and Landscape Replacement Areas requirements for new developments.

5.2.3.2 Façade areas for BAPV / BIPV

In an urban context, where space for solar deployment is limited, the vertical parts of buildings, particularly the façades of high- and medium-rise buildings (low-rise buildings often face shading from nearby objects, walkways and trees) could become key for expanding the areas for suitable PV installations.

In contrast to rooftop systems, façade installations also offer the possibility of replacing conventional materials of the building envelope with either building-added photovoltaics (BAPV) or building-integrated photovoltaics (BIPV). Such advanced building skins (e.g. in the form of solar curtain walls or shading devices with photovoltaic elements) are also one way for achieving Zero-Energy Buildings (ZEB) or even Positive Energy Buildings (PEB). BAPV and BIPV not only enable on-site energy generation on existing urban surfaces without the need for additional surfaces or infrastructure, but possibly also reduce the solar heat gain into the building.

<u>Opportunities for BAPV/BIPV in Singapore:</u>

In the area of façade development, there are five technologies where Singapore could significantly benefit and also become a front-runner in driving RD&D:

i. Coloured BAPV/BIPV modules;
ii. Pre-fabrication of BAPV/BIPV;
iii. “Transparent” PV windows;
iv. Ultra-light BIPV elements; and
v. PV-powered media walls.

5.2.3.3 Mobile-/land-based PV

Given the sizeable amount of empty land spaces at any given point in time, mobile-/land-based PV could be a game-changer for deployed PV capacity in Singapore. Solutions that allow timely relocation of PV systems at no significant cost, without impacting the underlying business case would be key to unlocking this in a broad scale.

Some companies have addressed the topic of "ease of deployment", by developing containerised solutions, as well as systems that can be swiftly deployed.

One such example is the pre-fabricated, expandable system from 5B in Australia, which allows to deploy a 12 kWp block within 10 minutes by two people (see video under https://vimeo.com/226409756). With such a system, it would be possible to move Megawatts of solar PV systems within a week.

There is ample room for optimisations and also for local assembly, as shipping structures from other countries would also bear substantial cost and CO_2 footprint.

It is noted here that JTC has added a research component to the SolarLand tenders whereby bidders can propose to (co-)develop innovative solutions for mobile systems, such as novel re-deployment options or mobile sub-stations for the grid interconnection.

5.2.3.4 Floating PV

In the area of Floating PV, the developments for Singapore would largely focus on "off-shore" or "near-shore" systems. There is already an established Floating PV industry for reservoir-based deployments, hence the lever for value capture over time would not be given.

In contrast, the industry for "near-shore" Floating PV system is not yet established. At this stage, only very few companies have deployed small-scale installations in marine environments.

In addition to "just" generating renewable energy, of particular interest for Singapore are the combinations with other uses, when it comes to deploying Floating PV in sea spaces, for example:

i. fish farming (also addressing *food supply*)
ii. hydrogen / solar fuel generation (also addressing *fuel generation*); and
iii. desalination (also addressing *fresh water supply*).

5.2.3.5 Infrastructure PV

To harvest the great potential for PV deployment in combination with existing land and infrastructures, there is more RD&D needed in the areas of:

i. Easy-to-deploy systems to over-arch existing infrastructures such as land, roads, canals with PV, without interfering in the original use of the land
ii. Noise barriers with noise absorption properties, which is often desirable in densely built-up neighbourhoods (rather than sheer noise reflection, as it is the case for traditional PV noise barriers)

5.3 Increasing energy yield

Apart from optimising the local deployment with PV, it is equally important to also maximise the energy generated from the installed capacity (i.e. applying technologies to increase the energy yield of the PV systems in the field).

The figure of merit is the "Performance Ratio" (PR). Well-designed PV systems in Singapore have an initial PR value of above 80%. Minimum PR for system installed under the SolarNova programme currently is ~75%.

There is a small annual degradation of the PV module output, which should be within the limits specified in the manufacture's performance warranty. Typical degradation rates for Singapore are ~0.8% p.a.

Figure 5.8 shows the loss components derived by simulations of a typical PV system deployed in Singapore. The analysis indicates that the - by far - largest PR loss (~7%) is attributed to the high temperatures at which PV modules are operating in Singapore's climate conditions. Therefore, system mounting with good ventilation or technologies that allow to reduce the module temperature (e.g. Floating PV) are very beneficial for increasing the energy yield.

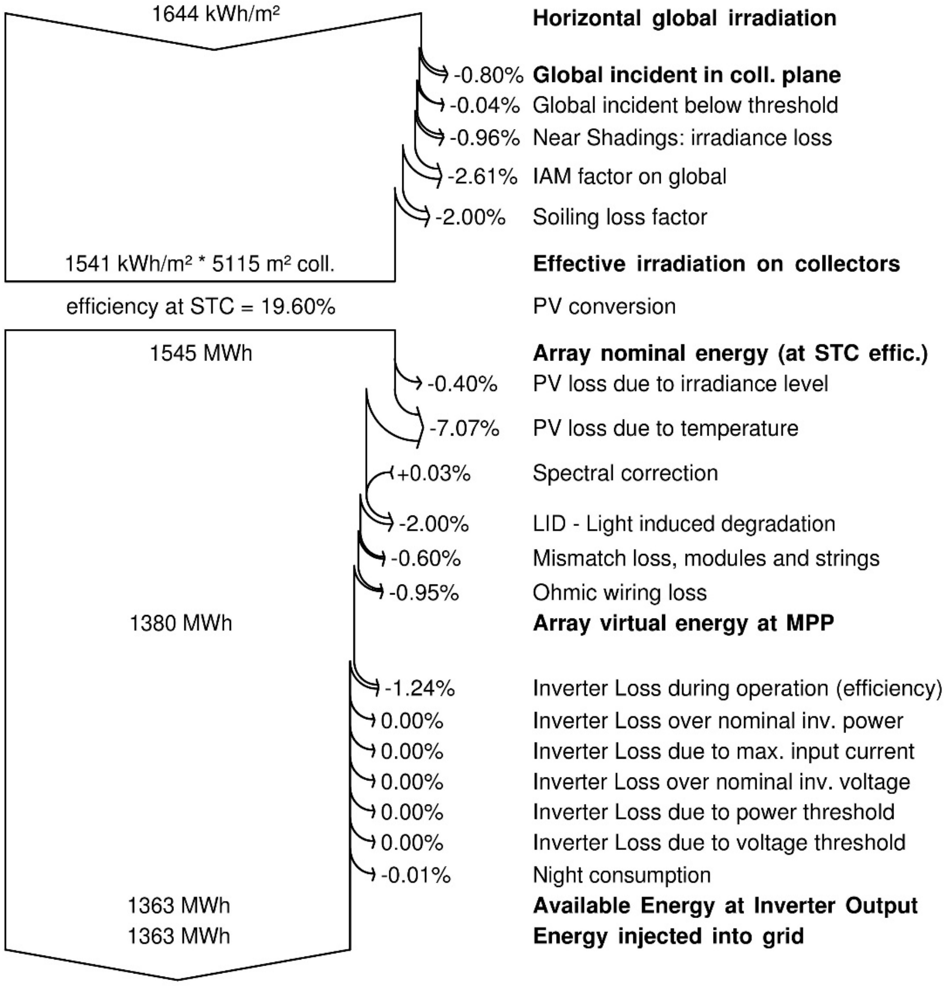

Figure 5.8: PR loss analysis of a typical PV system deployed in Singapore (using PV Syst software).

5.3.1 High yielding solar technologies

As shown above, out of the various loss components of a typical PV system, temperature is the major factor reducing the performance ratio and energy yield of PV systems in Singapore. The so-called “temperature coefficient” of the maximum power is an intrinsic material property of solar cells and henceforth depends on the choice of cell technology, cell device architecture, and the wiring interconnection in the PV panel.

Table 5.5 shows examples of the range of temperature coefficients for commercially available PV technologies.

Table 5.5: Temperature coefficients of the maximum power point (MPP) for various commercially available PV technologies. Source: module data sheets.

Technology	Manufacturers/products (examples)	Module efficiency	Temperature coefficient (of MPP)
p-type Multi-Si BSF	Trina, ALLMAX etc	16.2 %	- 0.41 (%/Kelvin)
p-type Mono-Si PERC	REC Peak Energy, Q CELLS	16.8 to 17.8 %	- 0.40 to -0.38 (%/Kelvin)
n-type Mono PERT	LGNeON2, LG NeONR	19.5 to 20.3 %	- 0.37 to -0.30 (%/Kelvin)
n-type Heterojunction	Panasonic N330, REC Alpha	19.7 to 21.5 %	- 0.30 to -0.26 (%/Kelvin)

It can be seen, that the temperature coefficients of high-efficiency n-type cell technologies, and heterojunction in particular, are substantially lower than those of current p-type cell technologies, which are deployed mostly in rooftop systems in Singapore today. The adoption of high-efficiency technologies is therefore not only beneficial to maximise solar deployment (as described in section 5.2.1), but also to increase the energy yield and hence harvest more solar energy for the same installed capacity.

The expected improvements in energy yields of PV systems deployed in Singapore due to improved system design and adoption of high-efficiency technologies are indicated in Table 5.6.

*Table 5.6: Projected performance ratios (PR) and energy yields for PV systems under the two scenarios, BAS and ACC (see also section 5.5), when using high-efficiency solar cell technologies. The assessment of future energy yields is based on the long-term average irradiance for Singapore of 1,644 kWh/(m2 * year).*

Projected future performance ratios (PR) [%] and Energy yield [MWh / (kW_p * year)], in part due to decreased temperature coefficient of high-efficiency PV modules						
Year	2020		2030		2050	
BAS	79%	1.30	80%	1.32	85%	1.40
ACC	82%	1.35	88%	1.45	90%	1.48

5.3.2 Smart O&M

The highly distributed nature of solar deployment along with the relatively small sizes of individual systems, e.g. on HDB blocks, puts forward an important challenge, i.e. to perform cost effective operation and maintenance (O&M) of the PV installations. In addition, the relative higher cost of manpower in Singapore, forces the system owner to efficiently manage the work load of the maintenance team; they must deploy them to the exact location along with the preliminary information about the fault rather than blank screening of all the systems deployed.

In this regard, smart O&M solutions based on long-term data using AI-based algorithms will be critical going forward. This will also enable early fault detection and targeted dispatch of service personnel. Given the leading RD&D landscape for AI in Singapore, there is ample room for innovations in this space. It also ties in with the projected developments in condition monitoring of power electronics such as:

1. Integrated chip-scale power converter for sub-module application and solution-specific micro-inverter for building integrated PV system;
2. Lightweight inverters for rooftop and wall mount applications;
3. Efficient and improved power density utility scale converters for grid connection; and
4. Integrated non-invasive diagnostic and lifetime monitoring tools at the component as well as module level utilising in-built sensors.

These challenges require innovative solutions in power electronics that could be tailored for the Singapore context. Though different topologies are available in market, their customisation for addressing the above constraints could unlock substantial innovation potential.

5.4 Levelised cost of electricity from solar PV (LCOE)

5.4.1 Summary of LCOE calculations

The cost of solar electricity is expressed in form of the “levelised cost of electricity” (LCOE), a well-established method in energy finance and policy for the calculation of the generation cost at the point of connection (to a load or the electric power grid). The LCOE is calculated by dividing the entire lifecycle cost of a solar PV system by its cumulative solar electricity generation. It is presented in net present value terms, with each year’s cost discounted by the investor’s hurdle rate.

Annex B gives a detailed overview of the methodology and the assumptions used here for the LCOE calculations of solar electricity in Singapore. It also provides LCOE calculations under different WACCs (weighted average cost of capital).

It is common in energy markets to compare various types of power generation sources based on their LCOE, thereby prioritising those providing the least cost option. This is called the merit order of generation sources. It is also understood that this methodology has its limitations, as it does not consider costs (or benefits) of externalities and ignores the time effect associated with matching power generation to demand, as well as the potential wider impact certain generation technologies (variable, non-dispatchable in particular) could have on the electricity system at large (e.g. transmission costs, balancing and reserve costs).

Notwithstanding these limitations, LCOE will be used in this context as a ranking tool to compare the competitiveness of various solar PV applications in Singapore. This ranking could be used by government agencies to prioritise certain deployment options or policy support to favour those with the biggest cost reduction potential.

Results of the merit order of solar electricity in Singapore are presented in Table 5.7 for 2020, 2030 and 2050. They are based on a WACC of 5%

Table 5.7: Merit order of the levelised cost of electricity (LCOE) for different PV applications in Singapore for 2020, 2030 and 2050. Numbers in [.] indicate changes in ranking from the previous timeframe

Merit order	Solar PV applications	Size	2020
1	Ground-mounted PV	Large (5 MWp+)	6.5
2	Rooftop PV	Large (1 MWp+)	7.6
3	Rooftop PV	Medium (300-600 kWp)	8.6
4	Floating PV inland	Large (5 MWp+)	9.7
5	Others: Overbuilding (land, roads, canals)	-	10.9
6	Rooftop PV	Small (below 300 kWp)	11.4
7	Others: Mobile PV containerized solution	Large (1 MWp+)	11.7
8	Rooftop PV	Very small 3 (50 kWp)	12.7
9	Floating PV near-shore	Large (5 MWp+)	13.4
10	Rooftop PV	Very small 2 (25 kWp)	13.4
11	Rooftop PV	Very small 1 (3 kWp)	15.6
Merit order	**Solar PV applications**	**Size**	**2030**
1	Ground-mounted PV	Large (5 MWp+)	4.2
2	Rooftop PV	Large (1 MWp+)	5.0
3 [4]	Floating PV inland	Large (5 MWp+)	5.6
4 [3]	Rooftop PV	Medium (300-600 kWp)	6.1
5	Others: Overbuilding (land, roads, canals)	-	6.8
6 [7]	Others: Mobile PV containerized solution	Large (1 MWp+)	7.1
7 [9]	Floating PV near-shore	Large (5 MWp+)	7.7
8 [6]	Rooftop PV	Small (below 300 kWp)	7.8
9 [8]	Rooftop PV	Very small 3 (50 kWp)	8.7
10	Rooftop PV	Very small 2 (25 kWp)	9.1
11	Rooftop PV	Very small 1 (3 kWp)	10.8
Merit order	**Solar PV applications**	**Size**	**2050**
1	Ground-mounted PV	Large (5 MWp+)	3.8
2 [3]	Floating PV inland	Large (5 MWp+)	4.4
3 [2]	Rooftop PV	Large (1 MWp+)	4.5
4	Rooftop PV	Medium (300-600 kWp)	5.2
5	Others: Overbuilding (land, roads, canals)	-	5.7
6	Others: Mobile PV containerized solution	Large (1 MWp+)	5.9
7	Floating PV near-shore	Large (5 MWp+)	6.1
8	Rooftop PV	Small (below 300 kWp)	7.2
9	Rooftop PV	Very small 3 (50 kWp)	7.9
10	Rooftop PV	Very small 2 (25 kWp)	8.4
11	Rooftop PV	Very small 1 (3 kWp)	10.0

5.4.2 Life-cycle cost calculations for BAPV / BIPV

For the case of building-added or building-integrated PV (BAPV / BIPV), the economic case is different, as BIPV typically replaces a conventional building façade element, for example a cladding. Therefore, the cost comparison is then against the traditional building material rather than conventional electricity generated.

As such, the figure of merit for BIPV is the "lifecycle cost" (LCC). A typical LCC analysis for BIPV in Singapore was carried out, using the input parameters as listed in Table 5.8.

Table 5.8: Main input parameters for the BIPV lifecycle cost (LCC) calculation

LCC (main calculation parameters)	Coloured BIPV facade	Traditional cladding facade
BIPV system (capex)	490 SGD/m^2	--
Cladding system (capex)	--	390 SGD/m^2
O&M for BIPV system (annually)	4 SGD/m^2	n/a
Cleaning (annually)	4 SGD/m^2	4 SGD/m^2
Base of electricity value	Contestable rate	n/a
Inflation rate	1.7% p.a.	1.7% p.a.
Performance ratio	80%	n/a
Degradation rate	0.8% p.a.	n/a

Figure 5.9 shows the comparative LCC of a conventional cladding and a coloured BIPV façade.

It can be seen that the BIPV façade has initially a higher capex, but eventually becomes lower in cost than a traditional cladding façade, through the value of the generated electricity. This calculation does not take into account that there are possible other benefits, for example a lower solar heat gain into the building, which could lead to a lower cooling load.

Figure 5.9 also shows the BIPV LCC results for two different in-plane annual insolation values: 750 kWh/m^2/year and 500 kWh/m^2/year. Section 5.1.2.6 had described, that by lowering the irradiance threshold for walls from 750 to 500 kWh/m^2/year, there could be a 7-fold increase of deployment area. From the graph it can be seen that such reduction would increase the payback from ~8 to ~13 years, which might be acceptable for some building owners, given the minimum 30-year time horizon of a building in Singapore.

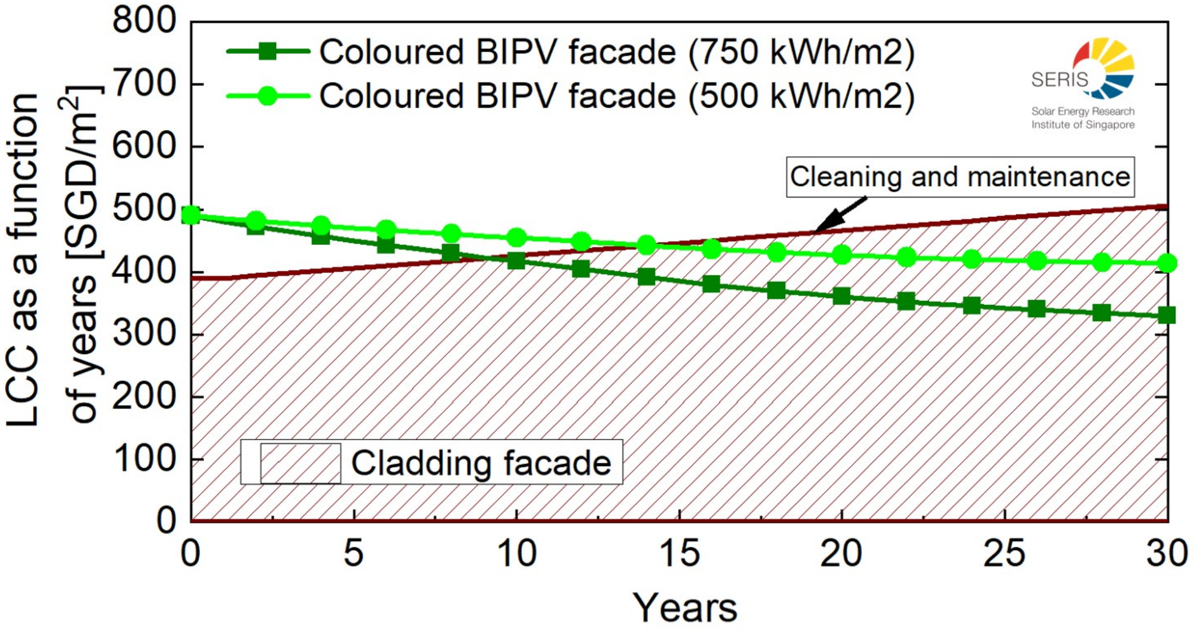

Figure 5.9: Comparative lifecycle cost analysis of a coloured BIPV façade (at two different annual insolation values) and a conventional cladding façade.[1]

Reference is also given to the BIPV LCC calculator on the "National Solar Repository" (NSR) website:

https://www.solar-repository.sg/lcc-calculator/ [2]

[1] Source: V. Shabunko, adapted from V. Shabunko, T. Reindl, "High-level financial assessment of coloured BIPV façade: Case study in Singapore", Proceedings of the 46th IEEE Photovoltaic Scientific Conference (PVSC-46), Chicago (IL), 2019.

[2] Based on: V. Shabunko, M. Bieri and T. Reindl, "Building Integrated Photovoltaic Facades in Singapore: Online BIPV LCC Calculator," 2018 IEEE 7th World Conference on Photovoltaic Energy Conversion (WCPEC) (A Joint Conference of 45th IEEE PVSC, 28th PVSEC & 34th EU PVSEC), Waikoloa Village, HI, 2018, pp. 1231-1233.

5.5 Possible scenarios for PV deployment

Similar to the original PV Roadmap, a scenario-based approach was adopted for this update project to describe various deployment possibilities.

The two scenarios are associated with different levels of adoption and technological advancements:

"Baseline" (BAS):

- An effective area of 6.7 km^2 (~18% adoption rate) in 2030, and 12.8 km^2 (~35% adoption rate) in 2050 is utilised for PV installations;
- Main drivers are government-led projects (HDB, SolarNova, Floating PV);
- An evolutionary use of high-efficiency technologies and better system performance is assumed (following Tables 5.4 and 5.6).

"Accelerated" (ACC):

- An effective area of 13.1 km^2 (~36% adoption rate) in 2030, and 20.1 km^2 (~55% adoption rate) in 2050 is utilised for PV installations;
- Main drivers are government-led projects (HDB, SolarNova, Floating PV), combined with a strong adoption by the private sector (industrial sector) and novel PV applications such as BIPV, near-shore floating and mobile / land-based PV installations;
- A substantial use of high-efficiency technologies and better system performance is assumed (following Tables 5.4 and 5.6).

The starting point for the scenarios is the summary of available surface areas for solar PV deployment from section 5.1.2.6.

From there, many scenarios are perceivable. Table 5.9 gives an overview of the two different scenarios, differentiated by total installed capacities (in MWp), respective energy yields (in TWh/yr) and CO_2 emission savings (in Mt/yr).

Some general remarks:

- The different scenarios are associated with different area factors (higher efficiencies assumed for more aggressive scenarios);
- The different scenarios are associated with different energy yield harvesting (higher system performance assumed for more aggressive scenarios);
- All scenarios include "re-powering" (see later section 6.1), i.e. after 20 years the original area is assumed to be re-utilised with - then higher efficient - PV systems;
- For BIPV, as indicated in section 5.1.2.6, only areas with more advantageous insolation (750 kWh/m^2/yr) are taken into account.

It is noted here that the scenarios only assume partial adoption for many possible areas, which widely de-conflicts the alternative use of space for enhancing greenery in Singapore as part of the "City in Nature" vision (see section 5.1.1) or concerns regarding PV deployment on infrastructure spaces.

<u>Table 5.9:</u> Overview of deployment scenarios BAS and ACC, and their impacts on PV power generation and CO_2 emission savings.

Scenarios		**Assumed System Peak Demand [MW]**	**Installed PV Capacity [MW_p]**	**PV Power Penetration Level[1]**	**Estimated Annual Electricity Supplied and Percentage of Total Demand (in brackets)**	**CO_2 emission savings [Mt/a]**
2030	BAS	9,000	1,000	11%	1.28 TWh (1.8%)	0.54
	ACC		2,500	28%	3.16 TWh (4.5%)	1.32
2050	BAS	11,500	2,500	22%	3.09 TWh (3.4%)	1.59
	ACC		5,000	43%	6.64 TWh (7.4%)	3.42

[1] defined as PV peak power during mid-day (solar noon) over the assumed system peak demand

<u>Note:</u>
The system peak demand and annual energy consumption for 2030 is extended from the 2029 outlook from the Singapore Energy Market Outlook (SEMO) for 2018. The 2030 demand figures represent an approximate 35% increase based on 2018 numbers. The demand for 2050 has been further extrapolated with a tapering off in demand growth from 2040; for an effective growth rate of 72.5% based on 2018 numbers.

Following the review of the 2014 PV Roadmap in section 4.2, the updated values for the projected installed capacities in 2030 and 2050 for the two scenarios are lower. This is largely due to the fact that the initial uptake of solar PV was assumed back then to happen much faster, i.e. by 2020 it was projected to already have 650 MWp (BAS) or even 900 MWp (ACC), respectively. This compares to the actual installed capacity of 300 MWp by Q3 2019, and an estimated ~400 MWp by end 2020.

5.6 Managing PV grid integration

Apart from space maximisation, managing the high variability from solar PV is one of the key concerns and perceived barriers for a large-scale adoption of solar PV in Singapore. This section references countries/regions with high penetration of variable renewables, and the mitigation measures introduced to ensure stability in their respective grids. It then also assesses possible grid impacts for Singapore for different levels of solar penetration under the two scenarios, BAS and ACC, as laid out in section 5.5.

5.6.1 Global developments

A comprehensive literature survey was carried out to understand how different countries/regions are coping with increasing levels of solar PV in their respective power systems.

The following countries/regions were selected for the literature survey: Japan and Germany, considered by many as 'pioneers' in the deployment of PV and in the development of PV regulations and policies. Hawaii, which has a comparable power system to Singapore, as it is a tropical region with a similar grid size and without grid interconnection to mainland US. Australia and California, which have in recent years faced grid-related challenges, such as the well-known 'duck curve' issue, due to increasing penetration with variable renewable energies.

Their current power system status and the penetration levels with solar PV are summarised in Table 5.10 (with most updated statistics publicly available and reachable to the authors).

Common challenges faced by the aforementioned countries/regions in solar PV grid integration due to the variable and distributed nature of solar PV, albeit in different levels of occurrence and severity for each country/region, are:

- Demand profile and ramp rate impact
- Distribution network impact
- Inertia and reserve requirements
- Protection system

These challenges were also assessed for the case of Singapore. Results are presented in section 5.6.3.

5.6.2 Grid mitigation measures for PV

The countries/regions mentioned above have addressed the challenges through a wide variety of mitigation measure and technologies. In general, PV grid integration measures can broadly be categorised in four different types:

1. **Supply & Demand-side management** (including flexible conventional generation and forecasting) – whether centrally controlled, or via incentives for user response to system needs. This typically represents the lowest-cost option for balancing the system.

Table 5.10: Overview of power grid status and solar PV penetration in countries with high adoption rates of variable renewable energies. Penetration level is defined here as the ratio of installed capacity to system peak demand (in %)

	Japan (2015) [1]	**Germany (2017) [2]**	**Hawaii (2014) [3]**	**Australia (2016) [4]**	**California (2017) [5]**
Size of Power System (GW)	315.3 (2014)	202.5 [6]	2.785	67 (NEM: 47) (2017)	79.6
Interconnectivity	National grid (50/60 Hz – West/East grid)	Part of the Continental Europe Grid	Islanded grids	Cross-state interconnected grid	Interconnected with other regions
Total Energy Generated (TWh)	1,009	602.4	10.5	257.5 (2016)	206.3
Peak Demand (GW)	159.1	79.8	Oahu: 1.141 Maui: 0.195 Hawaii: 0.189	38.8 (2016)	50.1 [7]
Renewable Targets (energy)	2030: 22-24% Wind (1.7%) Solar (7.0%) [8]	2025: 40-45% 2035: 55-60% 2050: ≥ 80% [9]	2045: 100% [10]	2020: 23.5% [11]	2026: 50% 2030: 60% 2045: 100% [12]
Solar PV Capacity in GW_p*	23.3 (15%)	43 (54%)	0.31 (10.7%)	4.36 (11%) [2015]	9.58 (19%)
Variable Renewable Energy in GW_p**	26.1 (16%)	99.3 (124%)	0.51 (18%)	8.59 (22%)	15.18 (30%)
Renewable Energy Capacity (GW)	Hydro: 49.6 Geothermal: 0.5 Wind: 2.8 [in 2014]	Geothermal: 0.012 Wind: 56.3 (51 onshore)	Hydro: 0.031 Geothermal: 0.038 Wind: 0.202	Hydro including pumped hydro: 8.72 Wind: 4.23	Hydro: 14 Wind: 5.6 Solar thermal: 1.2

* Penetration level in percentage shown in brackets
** Variable Renewable Energy (VRE) consists of solar and wind power

2. **Energy Storage Systems (ESS)** – Energy storage is a net consumer of electricity due to efficiency losses, but it enables greater PV penetration by buffering high variability and shifting energy from periods of low demand to periods of high demand, which reduces curtailment and eases integration challenges.

3. **Grid Upgradation** – this would be a software-driven solution, but would constitute a 2-3-year program to (i) implement models and algorithms to introduce self-healing capability and outage management, (ii) re-align the historical “hierarchical” architecture of the grid to allow multiple distributed generation, storage and demand points to transact with each other, and (iii) create the transactive platforms to enable them to do so. Aside from providing robustness / stabilisation to the grid, application of Smart Grid and IoT based technologies can lead to substantial reduction in consumption as well as losses.

4. **New Equipment** – depending on the specific characteristics of the grid, the residual grid stabilisation needs can be addressed with hardware solutions at both central and local levels.

It should be noted that very few of these solutions are exclusive to any of the four problem statements outlined in the previous section. In fact, several of the identified solutions come with the advantage that they can address multiple challenges, thereby improving their cost-efficiency. Overall solutions will likely consist of a balanced portfolio of mitigation measures.

The ADDENDUM to the "Update of the PV Roadmap" gives a detailed overview of the various mitigation technologies and their current status of implementation globally. It also provides further information on the benefit and importance of Smart Grids, IoT and cybersecurity for PV grid integration.

5.6.3 Grid impact assessment of PV in Singapore

As shown in section 5.6.1, many countries/regions have a portfolio of renewable energy resources (e.g. PV, wind, hydro, geothermal, etc.), including those which are dispatchable. In Singapore, the most viable renewable option is solar PV, which is inherently variable and non-dispatchable. However, due to the tropical climate conditions and frequent changes in cloud cover, Singapore's solar output is highly variable. Singapore's PV installations are also largely dispersed (e.g. on rooftops) and connected to the low-voltage distribution network. This could give rise to additional challenges, in particular the lack of visibility and control over a large generation fleet that is embedded in the distribution network.

Approach of the Grid Impact Study
Following the benchmark study, the focus of this assessment was on the four aspects:

- Demand profile and ramp rate impact
- Distribution network impact
- Inertia and reserve requirements
- Protection system

The assessment was carried out for the BAS and ACC scenarios presented in section 5.5. The relevant input data are reproduced in Table 5.11.

Table 5.11: Overview of deployment scenarios BAS and ACC, and the data used for the grid impact assessment.

Scenarios		System Peak Demand [MW]	Installed PV Capacity [MW_p]	PV Penetration Level[1]	Estimated Annual Electricity Supplied and Percentage of Total Demand (in brackets)
2030	BAS	9,000	1,000	11%	1.28 TWh (1.8%)
	ACC		2,500	28%	3.16 TWh (4.5%)
2050	BAS	11,500	2,500	22%	3.09 TWh (3.4%)
	ACC		5,000	43%	6.64 TWh (7.4%)

[1] defined as PV peak power during mid-day (solar noon) over the assumed system peak demand

Note: The system peak demand and annual energy consumption for 2030 is extended from the 2029 outlook from the Singapore Energy Market Outlook (SEMO) for 2018 [13]. The 2030 demand figures represent an approximate 35% increase based on 2018 numbers. The demand for 2050 has been further extrapolated with a tapering off in demand growth from 2040; for an effective growth rate of 72.5% based on 2018 numbers.

Assumptions:

Furthermore, unless otherwise stated, the following assumptions have been made:

- Changes in climate conditions were not considered; high-resolution weather data from 2018 were used for the analysis;
- Changes in consumption behaviour patterns (due to price changes) were not considered. The aggregated load demand pattern was assumed to remain the same and the projected load growth (for each scenario) will proportionally increase the existing pattern;
- No curtailment of solar PV output was taken into account. Balancing requirements will have to come from existing generation / reserves / demand-side response mechanism;
- Pricing due to market-related considerations / stimulations was not taken into account. Dynamics involving generation contracts (for contestable consumers) were not considered;
- Current grid codes as of end-2018 were used as a base. Additional requirements in grid codes/regulations for solar PV inverters such as, responding to changes in voltage or frequency, responding to PSO commands or fault-ride through (FRT) support were not taken into account;
- Virtual Power Plants (VPP) with direct access / control of a larger fleet of PV installations were not considered;
- PV penetration level is defined as the ratio of PV installed capacity to peak load in the network.

5.6.3.1 Demand profile and ramp rate impact

The California Independent System Operator (CAISO) published the famous “duck curve” in 2013 to highlight the problems of (i) over-generation of PV during the day and (ii) extreme ramp rate requirements around sunset, when the solar generation goes to zero and the evening demand peak occurs. At higher penetration levels the conventional power system may not be able to accommodate these challenges anymore [14].

A study was conducted based on Singapore’s demand profile to understand, if similar challenges would be faced here as PV penetration level increases. For this study, Singapore’s electrical load demand for 2018 was obtained from Energy Market Company (EMC) website. The PV model is a theoretical model with the following assumptions:

- Clear sky irradiance profile is considered in the model;
- Irradiance of 1,000 W/m^2 produces rated PV power;
- Solar noon is assumed at 1 pm with little variation in sunrise and sunset timing over the year;
- Load demand shape in 2030 and 2050 does not differ from 2018 other than due to load growth (i.e., profile shape remains the same);
- PV power dispatch is prioritised over conventional fossil fuel based generation.

Figure 5.10 shows the typical load demand in Singapore in 2018. Unlike the CAISO duck curve, Singapore’s demand profile is comparably flat with the peak occurring between 9 am – 5 pm and the load valley appearing at around 3 am – 4 am. The load profile on Saturdays and Sundays are much lower than on weekdays with a difference in peak demand of 1 to 2 GW; approximately 15% of system peak demand.

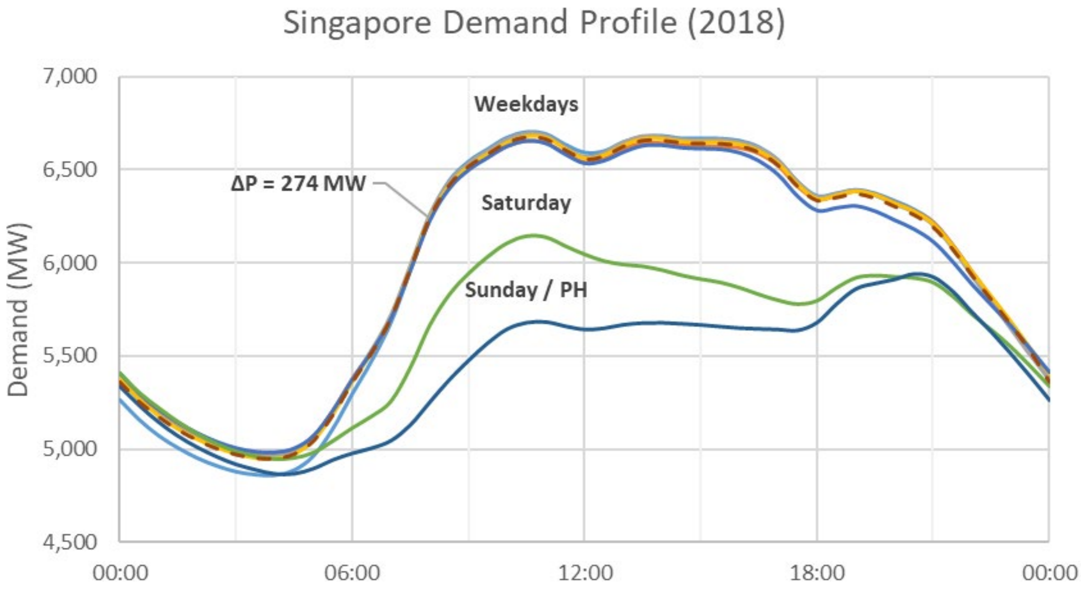

Figure 5.10: Singapore typical day load demand in 2018 for weekdays, Saturday and Sunday / Public Holiday (PH). ΔP indicates the maximum average inter-period ramp rate.

Impact of PV penetration level on net generation

Based on the two scenarios (see data listed in Table 5.11 above), the projected net system demand profiles for 2030 and 2050 are shown in Figures 5.11 and 5.12, respectively.

In the 2030 BAS scenario, PV generation smoothen the daily demand curve with the ramp rate expected to slightly increase; however, this will not pose a risk to the current power grid.

In the ACC scenario, the system minimum demand decreases to 5,270 MW. The daily typical ramp rate for the 2030 ACC scenario is expected to double. The power grid is expected to be able to accommodate PV at these levels, at the cost of increased thermal stress to the generators.

As PV penetration level increase in the 2030 ACC scenario, additional challenges are expected in generator scheduling due to technical constraints. Varying the types of generator in the system could provide added flexibility.

In the 2050 scenarios, the projected system peak demand is expected to increase to 11.5 GW. In the 2050 BAS scenario, net demand ramp rate is projected to reach 844 MW/period with a minimum system demand of 7,740 MW. This scenario should not pose any significant threat to the stability of the current system.

In the 2050 ACC scenario, maximum ramp rate is expected to reach 1,517 MW/period with a system minimum demand of 5,030 MW. In this scenario, it is expected that the current (2018) capability of generators will be still able to accommodate such requirements, at the cost of reduced overall efficiency.

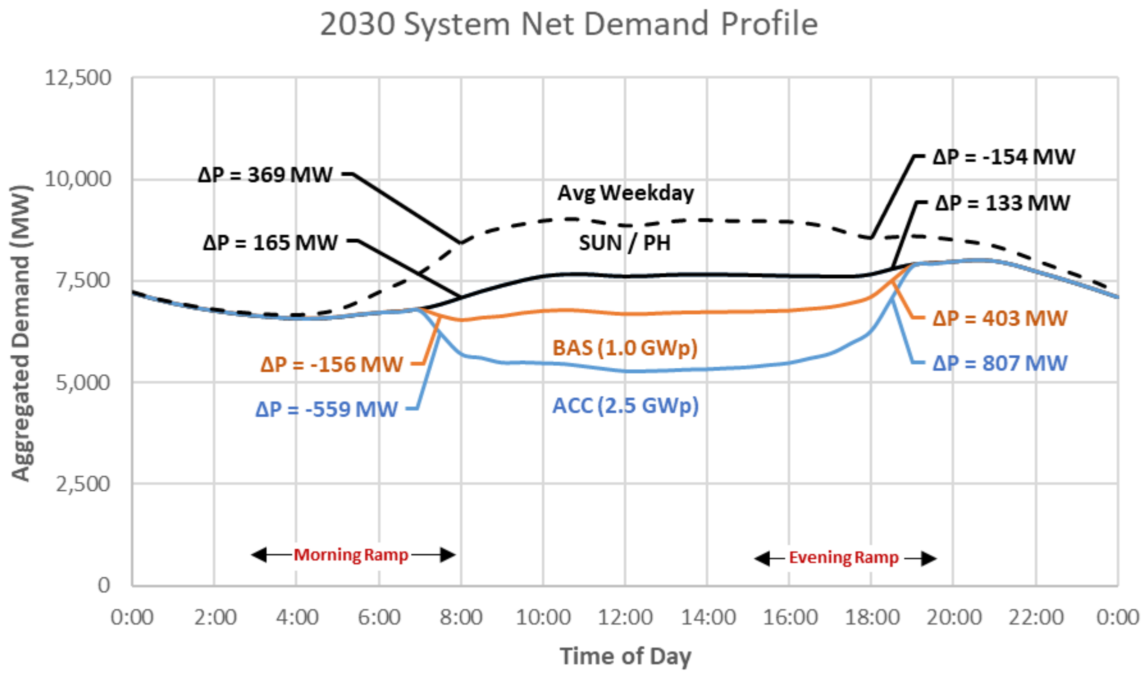

Figure 5.11: *Singapore 2030 demand profile and impact under the BAS and ACC scenarios. ΔP indicates the maximum average inter-period ramp rates.*

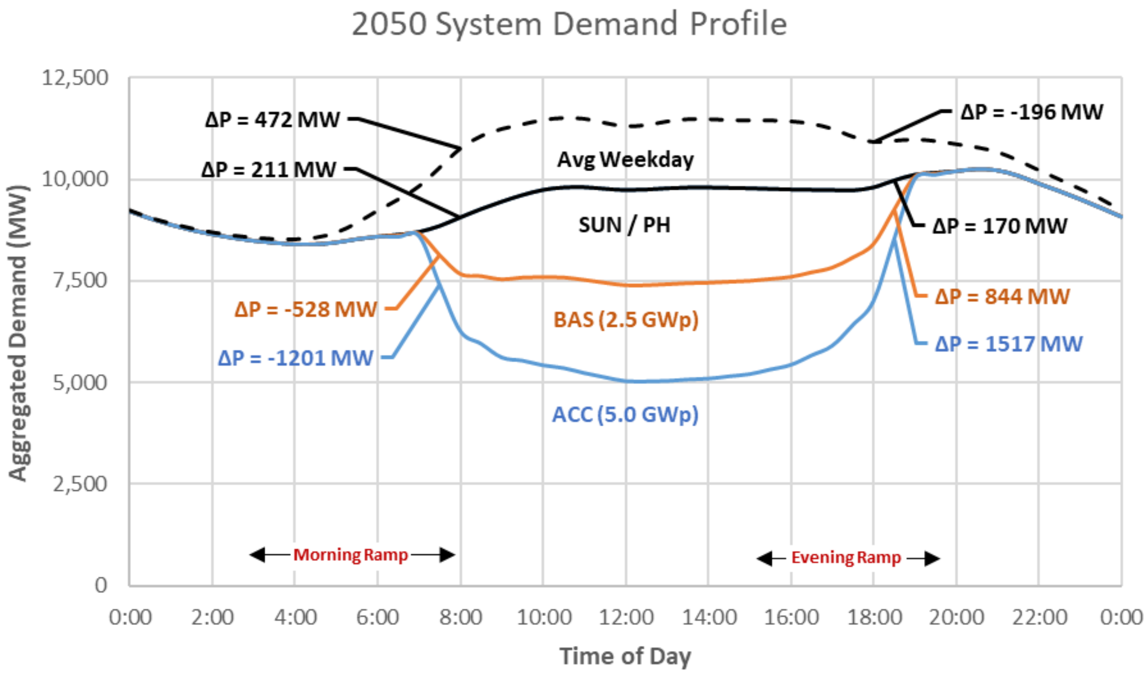

Figure 5.12: *Singapore 2050 demand profile and impact under the BAS and ACC scenarios. ΔP indicates the maximum average inter-period ramp rates.*

Worst case scenario

While Singapore is largely shielded from natural disasters, regional meteorological events can still impact Singapore. Typhoon Lan was the third most intense tropical cyclone in 2017, mainly affecting the east coast of Japan and the Philippines, and resulted in a rapid increase of cloud cover over Singapore due to the large trailing edge of the storm. Historical island-wide irradiance measurements indicated an average magnitude drop of 700 W/m^2 over 30 minutes.

In order to understand the impact of such an event on the Singapore grid, a similar event was reconstructed using the data from the Typhoon Lan event and applied across 2030 and 2050 PV scenarios.

Insufficient ramp rate capacity is expected for the 2050 ACC scenario for such rapidly changing weather events. One way to increase the ramp rate capacity is to account for short-term weather forecast to dispatch additional generators prior to the expected loss of PV output events (like such thunderstorms). Additionally, a reduction of dispatch interval or the introduction of multi-interval dispatch for fast response generator or ESS could be also helpful in improving ramp rate capacity when required. Incorporation of different types of CCGTs (Combined Cycle Gas Turbine), traditional and fast-reacting, could also help to ensure system ramp rate remains in acceptable limits as PV penetration increases.

5.6.3.2 Distribution network impact

Due to the land constraints in Singapore, a large portion of Singapore's PV installation will be located at the distribution network. Potential impacts on the distribution network due to the PV integration include reserve power flow, overvoltage along the distribution line, loss of voltage control and phase unbalance, etc. [15]. A report by the National Renewable Energy Laboratory (NREL) in 2013 details the impact of high PV penetration on the distribution network in Oahu, Hawaii [16]. In the analysis, voltage and thermal limits are defined by the Hawaiian Electric Company (HECO) and no limit is defined for PV penetration based on the assumption that no potential PV was added greater than the line thermal limit. It was determined for Oahu that the voltage and thermal steady state limits are highly dependent on the location of PV

<u>Impact of PV penetration on distribution network voltage</u>

A typical 22 kV distribution network in Singapore was modelled down to the 400 V low-voltage level, while assuming the 66 kV incoming line as an infinite bus. A static power sweep study from 100% net consumption (representing heavy load) to 150% net injection (representing high PV installed capacity) was conducted to investigate the impact of PV on the distribution network voltages.

No immediate voltage concerns (excursion outside the regulation limit of ±6% [17]) were observed. It has to be noted that the impact on distribution networks are highly dependent on the electrical connection points of the PV systems and the distribution network architecture.

5.6.3.3 Inertia and reserve requirements

Traditional generation units such as coal- or gas-fired power plants are based on synchronous generators that contribute electrical inertia to the power system from their rotating mass. Electrical inertia can be described as a resistance to change in system frequency. A high electrical inertia power system is thus able to reduce the "Rate of Change of Frequency" (RoCoF) following system imbalances such as the sudden loss of generation or load. PV systems are inverter-based technologies which are non-synchronous in nature and do not contribute electrical inertia to the power system.

Variation of the frequency beyond the permissible range can lead to load-shedding and even disconnection of generators. If not immediately addressed, these events could result in a cascading failure of the entire grid in extreme cases. One of the recent incidents in South Australia is a real-world example of the impact of a decreased inertia. A severe storm led to a cascading transmission network failure due to the tripping off of multiple wind farms, which triggered a shutdown of the interconnector and resulted in a blackout in South Australia on 28 September 2016 [18].

Non-synchronous PV installations in Singapore as of Q3 2019 was ~300 MW_p (about ~4% penetration level) [19] and is likely to reach ~400 MW_p by 2020 (~5% penetration level). High RoCoF is unlikely to occur in Singapore before 2030 and only beyond ~4 GWp of installed PV capacity it is recommended to carefully monitor the grid inertia.

Several grid scale mitigation measures, such as synchronous condensers and fast response ESS, have been explored by different countries in dealing with the decreasing inertia challenge. Among these mitigation measures, Fast Frequency Response (FFR) is considered as an effective tool to arrest frequency changes following a contingency event by rapidly injection active power. One other possible mitigation measure that could be employed to help address the impact of decreased system inertia is demand response. In the updated grid code [20], the minimal size to participate in demand response has been lowered to 100 kW. This would enable a considerable increase in demand side participation of frequency regulation for the Singapore power grid. Changes to the dispatch algorithms to include consideration of system inertia requirements and weather forecast could be employed to help mitigating some of the impact of a lower inertia system. Condition monitoring could also be used to help detect and identify early signs of degradation of generator performance to reduce to likelihood of unexpected failures.

5.6.3.4 Protection system

The protection system in an electrical network is crucial for the safe operation of any electrical network. These protection systems safeguard assets and components against damage when a fault or abnormal situation occurs. The protection system also serves to reduce and limit the amount of affected load or customers. Replacement of conventional synchronous generation with non-synchronous inverter-based distributed PV generation changes the assumption of how existing centralised generation electrical grid are protected, especially for non-unit protection[1] and at high penetration levels.

<u>Decreasing System Fault Capacity</u>

Non-synchronous inverter-based PV generation typically are not required to supply fault current. In cases where such inverters are required to provide fault current, the capability is often much less (often in the range of one to two times of the rated current) compared to synchronous machines (in the range of five to seven times of the rated current). This

[1] These typically form the backup protection system in the Singapore power grid and supplements the main protection systems.

reduced fault current capability is largely due to the thermal constraints of the semiconductor devices in the PV inverter. In order to alleviate the impact of decreasing network fault current capability, one counter-measure is to allow or require inverter-based generation to provide as much fault current as possible. This has also prompted the call for “Fault Ride Through” (FRT) provision of inverters in countries with a high proportion of non-synchronous generation. There are two main types of FRT; “partial” and “full” FRT.

“Partial” FRT only requires that PV inverters remain connected and online during voltage excursion events. “Full” FRT requires that inverters also supply fault current during the fault event.

Also, more intelligent protection systems, such as adaptive protection relays, may be desired to ensure consistent performance of the protection system. However, such measures may require additional investment in new relays or communication infrastructure between network components.

5.6.3.5 Summary of possible grid impacts

From this initial grid impact study, the Singapore power system in its current form should be able to accommodate 2 GWp of PV (2030 ACC) without major concerns or required modifications. At higher PV penetration levels, power factor and ramp rates should be closely monitored, with deployment of mitigation measures to address power and voltage variation in the grid. It also should be noted that the impacts highlighted in this roadmap are not exhaustive and more detailed assessment is required for planning and evolving the future power system structure in the presence of an increasing fleet of solar PV generators.

While this section mainly addresses negative impacts of PV adoption on the power system, especially at high penetration levels, it should be noted that it is possible to also derive positive impacts to the grid, e.g. through provision of ancillary services such as voltage support. This is especially the case with the combination of other mitigation measures, which could provide greater benefits than through efficient integration. In addition, smart grid and IoT based technologies (see ADDENDUM) will become increasingly important, both for grid condition monitoring and grid management.

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6 NEW TOPICS of the "PV Roadmap for Singapore"

6.1 Re-powering

"Re-powering" is the replacement of ageing power generation equipment with latest technologies that have higher efficiencies, better performance, and often also higher reliability. It is well known in the wind industry where over the years the size of wind mills and hence the maximum power generation per tower increased substantially. The development of wind power project sites typically takes several years, therefore, it is often more economic to use the existing permits and generate more power from the same location through "re-powering" when compared to starting a new development.

With recent increases in PV efficiencies and with substantially falling solar module prices over the past 5-8 years, system owners around the world are also considering re-powering for PV installations. For the case of tropical Singapore, this may well be triggered by increased system losses from degradation or soiling.

"Re-powering" needs to be carefully calculated for each project to determine whether it makes economic sense, as the additional cash outflow for the new equipment was not originally planned. To offer a benefit, the increases in energy yield and revenues must outweigh the efforts to replace components.

There are also multiple considerations on the technical side, as the PV module replacements may not fit onto the original support structures anymore and quite likely the inverter matching (DC-to-AC ratio) will also not be optimal. As such, "re-powering" of a PV installation requires not only the exchange of the PV modules, but also of the inverter and possibly the associated cabling. One typical point in time for the consideration of "re-powering" would therefore be when inverter replacements are due to take place.

On the commercial side, it is also important to verify whether existing contractual agreements such as licences and PPAs allow for re-powering, or if they would need to be altered/re-negotiated to include such "step-changes" in capacity and energy yield.

6.2 Recycling

With the global exponential growth in installations and aging of PV modules, the need for PV recycling is increasing worldwide, especially in those parts of the world where PV programs were started nearly two decades ago. A study conducted by International Renewable Energy Agency (IRENA) showed that PV waste was around 250 tonnes in 2016, but is expected to grow to 1.7-8 million tonnes by 2030[1].

Recycling is imperative in the PV value chain for proper management of the growing PV waste and for the technology to maintain its environmentally-friendly and clean status.

[1] IRENA, IEA PVPS, End-of-Life Management of Solar PV Panels (*https://www.irena.org/documentdownloads/publications/irena_ieapvps_end-of-life_solar_pv_panels_2016.pdf*).

Development and implementation of PV recycling solutions is two-fold: 1. policy-based regulations, and 2. technological improvements.

1. Currently, only Europe has a strong regulatory framework for PV Module recycling, while other countries are only starting to build specific legislations. The European Union (EU) provides a framework for extended producer responsibility of PV modules through the Waste Electrical and Electronic Equipment (WEEE) Directive 2012/19/EU. In late 2017, the Japan Photovoltaic Energy Association (JPEA) has published voluntary guidelines on how to properly dispose of "end-of-life" (EoL) photovoltaic modules. On the other hand, countries with fast expanding PV markets such as China, India and USA still lack specific regulations for EoL PV modules. These countries classify PV waste under a general regulatory framework for hazardous and non-hazardous solid or electronic waste. Currently, only about 10% of EoL PV modules are recycled worldwide.

2. In terms of recycling technologies, there are more than 120 patents from various countries for recycling of PV Modules, the largest share coming from China. There is huge competition between research institutes and corporations along the lines of improving the process efficiency, lower energy consumption economics, recovery and recycling rates, as well as the environmental performance. Despite the large module waste expected worldwide, there are only few module recycling companies around the world.

For the case of Singapore, most PV systems (e.g. those installed under the SolarNova tenders) are leased by PV system developers and are subject to EoL take back services by the developers. A small fraction of PV systems is owned by building owners and/or estate managers and are not subject to such services. From 2021, a regulated system to manage e-waste will be implemented in Singapore that is built around the Extended Producer Responsibility (EPR) concept. Producers (i.e. importers, manufacturers) of PV panels will be required to provide free take-back services for EoL PV panels.

Singapore has a relatively young PV market, hence the need for recycling will only surface in the next 5-10 years. However, the need for PV recycling is aggravated by the fact that "re-powering" of old assets will bring the decommissioning of certain existing installations forward.

6.3 Renewable Energy Certificates (RECs)

RECs are tradeable, non-tangible market instruments that represent proof that electricity was generated from a renewable energy (RE) source. RECs are typically transacted in 1 MWh quanta as a balanced trade-off between granularity and ease of accounting. In Singapore, however, there are companies that claim to operate platforms allowing smaller (kWh) quanta to be traded to meet smaller volume demand, for example from residential consumers[1].

[1] The Straits Times, 30 Oct 2018 (https://www.straitstimes.com/singapore/easier-for-small-producers-to-sell-green-credits)

RECs represent proof that a generated amount of energy came indeed from an eligible RE source. They are eventually "retired" by an end-user as proof that the same quantity of energy was consumed. In general, RECs can be broadly classified in two categories:

- Bundled RECs, which are instruments whereby the "green attribute" is coupled with the electricity that is generated. Though not necessarily always the case, these can be packaged together in the form of a solar Power Purchase Agreement (PPA) from an electricity retailer, which guarantees that the electricity purchased is from a renewable source. Bundled RECs are generated and retired in tandem with the actual supply and consumption of electricity, and so are bound by certain considerations such as geographic constraints, i.e. the RECs have to be sourced from within the same electricity grid.

- Unbundled RECs, which are instruments whereby the "green attribute" is decoupled from the electricity that is generated. Unbundled RECs do not provide physical delivery of electricity from a renewable source, but rather its green attribute. The consumer may purchase electricity from a separate entity. Because of this, unbundled RECs allow for more flexible business models while enabling organisations to fulfil their sustainability obligations. For example, consumers purchasing unbundled RECs can look at a certain range of eligible generation dates (for example, up to 12 months prior to the reporting period), and select a desired quantum. At present, the extent to which unbundled RECs can be counted towards a sustainability goal largely depends on the organisation's internal reporting standards.

Regardless of the type, REC ownership provides consumers with an exclusive right to make sustainability claims about being powered by renewable energy. Hence, several registries have been developed to aid in the tracking and verification of RECs. Currently, the registries and platforms listed in Table 6.1 operate in Singapore.

Table 6.1: Overview of Renewable Energy Certificates (RECs) registries and platforms operating in Singapore (as of March 2020).

S/N	Name	Reference
1	APX TIGRs	https://apx.com/tigrs-overview/
2	I-REC Registry	https://registry.irecservices.com/
3	Reneum	http://www.reneum.com/
4	Sembcorp RECs	www.sembcorprec.com
5	Singapore Power REC Marketplace	https://rec.spdigital.io
6	T-RECs.ai	https://www.trecs.ai/

Drivers for RECs in Singapore

A growing number of companies in Singapore are also part of the RE100 consortium, led by The Climate Group together with CDP (formerly known as the Carbon Disclosure Project). The RE100 is a global corporate leadership initiative that brings together influential businesses committed to 100% renewable electricity usage by 2050 at the latest. Each organisation within the consortium has an internal mandate and a plan to meet its RE targets within a certain time frame.

Similarly, companies listed on the Singapore Exchange (SGX) have mandatory sustainability reporting, which in part could be fulfilled by using renewable energies. If a company does not have sufficient space on its premises for deploying its own solar energy systems or for solar leasing, RECs are a suitable alternative to actually demonstrate the use of renewable energy in the company's operation.

Additionally, the Building Construction Authority's (BCA) Green Mark scheme for Super Low Energy Buildings (SLEB) could be another significant driver for RECs in the future. The SLEB programme aims at pushing the envelope of environmental sustainability in Singapore by harnessing cost-effective energy efficiency and renewable energy solutions in the built environment sector. Under specific scenarios in the Green Mark scheme for SLEB[1], off-site renewable energies can already be counted towards the assessment criteria, after on-site renewable energy sources are maximised first. RECs could then be used as proof for the authenticity of the additional RE supply. With increasing encouragement from the Government towards higher levels of energy efficiency, BCA's Green Mark scheme for SLEBs could galvanise the adoption of RECs in Singapore to off-set a building's energy consumption. The use of RECs for assessment, however, is considered only after significant efforts have been made to reduce the energy demand and maximise on-site renewable energy generation, in order to avoid mis-alignments of incentives.

Given the growing interest in RECs, and the diversified way of how individual registries handle and verify transactions, the National Environment Agency (NEA), Enterprise Singapore (E-SG) and the Sustainable Energy Association of Singapore (SEAS) have started a process to develop standards for REC platforms in Singapore. This could serve as a useful reference for others around the region that are also considering adopting RECs to encourage renewable energy deployment.

6.4 Importing of solar energy

Given the space constraints for PV deployment in Singapore, one possible option to increase the share of renewable energy is by importing it from other countries. Such imports could be in the form of electricity (via cable connections) or through other energy carriers such as hydrogen (made from solar energy), which are often referred to as "solar fuels".

It is noted here that importing renewable energies is not restricted to solar power, but could also include for example wind power, bioenergy, hydropower or geothermal.

This section describes some technical concepts for importing solar power from other countries, but does not address the associated geopolitical, legal or financial risks.

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[1] BCA. (2018, September 5). *Green Mark for Super Low Energy Buildings* (retrieved November 20, 2019, from https://www.bca.gov.sg/GreenMark/others/GM_SLE.pdf).

6.4.1 Trans-border cable connections

6.4.1.1 PV system deployment in neighbouring countries

The variability of solar PV power output reduces with distance (geographic smoothing effect) as there is reduced probability of synchronised ramping events caused by clouds. For example, neighbouring PV installations are likely to be shaded by the same cloud, whereas PV installations deployed far from each other are not. Hence, increasing the effective area that can be used for the deployment of PV reduces the inherent variability of solar PV power whilst also dramatically increasing the amount of solar PV that can potentially be installed. For these reasons, it is of interest to explore the concept of installing solar PV in neighbouring countries.

Connecting PV installations in neighbouring countries to the Singapore grid would require either a dedicated trans-border cable or through grid interconnection to those countries (section 6.4.1.2).

In order to keep investment cost to a reasonable range, the proximity to Singapore and LCOE at the point of connection in Singapore should be considered for such installations.

6.4.1.2 Pan-Asian power grid interconnection

One option to add significantly more PV power to Singapore's energy mix whilst reducing solar variability is to explore stronger power grid interconnections between Singapore and neighbouring countries. In the long term, this could considerably increase the contribution of renewables (not only solar) to Singapore's electricity mix.

There are visions for trans-national super grids that would foster large scale utilisation of renewable energy sources beyond regional co-operation. Asia-Pacific "super grids" have already been proposed[1]. Such super grids would bring renewable electricity generation, storage and distribution opportunities to a new level. Though only a vision today, such super grids could form a basis for a sustainable regional energy supply system by the mid of this century.

6.4.2 Solar electricity imports over greater distances

6.4.2.1 Off-shore floating solar farms

A number of countries are exploring and developing technologies for off-shore floating solar farms, in particular the Netherlands, Belgium and Norway. Apart from powering off-shore structures from the oil & gas industries, the main targets are off-shore wind farms. In order to maximise the efficiency of wind farms, the turbines must be spaced substantially apart from each other so that turbines are not in the turbulent wake of an upwind turbine, otherwise they would suffer substantially reduced power yield. The area in between the towers would provide ample space for floating solar systems, provided that they are robust enough to withstand high and consistent wind speed and waves. Once robustness is achieved, co-

[1] For example: J.A. Mathews, "The Asian Super Grid," The Asia-Pacific Journal, Vol 10, Issue 48, No. 1, 26 Nov 2012

located solar farms could leverage the pre-existing transmission and interconnection infrastructure of the wind farms.

For the case of Singapore, such large-scale off-shore solar PV farms could, in-principle, be built in the international waters of the South China Sea and then supply solar electricity via subsea cables to Singapore. Sizes could be in the range of several hundreds of Megawatts, or even Gigawatts. In addition to the technical and economic challenges, such deployment option would, of course, require a number of considerations from security, safety to geopolitics. However, it is expected that within the timeframe of this roadmap (until 2050) there will at least be technical solutions available for this deployment option.

6.4.2.2 Long-distance cable connections

Given the ample resources of solar energy in Australia (annual insolation is approx. 1.5 times higher than Singapore), Asia-Pacific super grids inter-connecting Australia with Indonesia and eventually Singapore had been proposed in the past, although largely land-based[1].

Most recently (July 2019), the new venture SunCable (www.suncable.sg) has announced their aim to build a 10 GWp solar farm in Northern Territory, Australia and connect it all the way to Singapore via a subsea cable. The project would cover an area of 15,000 hectares in size and would be combined with some level of battery storage. It would be constructed in the desert outside of Tennant Creek, NT, from where it would first connect Darwin and then go via Indonesia (crossing between Bali and Lombok) to eventually reach Singapore. The subsea cable is estimated to range over a distance of 3,800 km. [2]

Technically, this would be, by far, the largest sub-sea cable connection anywhere in the world. Longest distances today are used for inter-connecting countries in the North and East Sea in Europe, which are in the range of 500-600 km. There are longer cable connections in plan or under construction, particularly the “EuroAsia Interconnector” in the East Mediterranean Sea, connecting Israel to Cyprus, Crete and Greece via a 1,518 km subsea high-voltage DC (HVDC) cable.

The projected landed cost of solar electricity in Singapore by SunCable are supposedly in the range of the long-run marginal cost (LRMC) of a combined-cycle gas-fired power plant here. It was not possible for the consortium to verify this without more detailed information about the plans and underlying assumptions.

It is obviously a very ambitious project and an implementation timeframe of a decade is probably the minimum one would need to consider, given the significant hurdles in terms of detailed technical feasibility studies, contractual agreements between multiple parties across three nations, signing off-take agreements for 20+ years and obtaining financing; just to name a few.

[1] A. Blakers, J. Luther, and A. Nadolny, “Asia Pacific Super Grid – Solar electricity generation, storage and distribution”, Green 2 (4), 2012, pp. 189–202

[2] Source: The Guardian (*https://www.theguardian.com/environment/2019/jul/14/just-a-matter-of-when-the-20bn-plan-to-power-singapore-with-australian-solar*).

6.4.3 Solar fuels

“Solar fuels” refers to the generation of energy carriers through the use of solar electricity. It is also called “power-to-gas” (P2G) or “power-to-fuel”, depending on the final product.

There are two different types of products to harness from this technology. The first being hydrogen (H_2) gas by electro-chemically splitting water into hydrogen and oxygen, and the second being different chemical feedstock (methane, ethanol, ethylene, synthetic gas, etc.) by reduction of carbon dioxide (CO_2).

Similar to a cable connection, there is also the possibility to import solar fuels from other countries, in particular those which have ample renewable energy resources. For example, Australia is a possible source where there are already activities underway to position the country as “exporter of renewable energies”. Australia recently released its national hydrogen strategy in November 2019, with an implementation timeframe of 2020 to 2030. One of Australia’s focus areas for hydrogen will be to develop and expand its hydrogen export industry, having identified South Korea, China, and Singapore as potential new markets. With several R&D initiatives to scale up and streamline hydrogen production and transport, Australia targets to produce cost competitive renewable hydrogen at AUD 10/kg for export around 2030.

Some of the evolving hydrogen activities in Australia are:

→ “The Asian Renewable Energy Hub” in Pilbara region (https://asianrehub.com)

The Asian Renewable Energy Hub expects to generate up to 15,000 MW of renewable energy (wind and solar) in Western Australia, the bulk of which would be used for the production of green hydrogen products for domestic and export markets. The outstanding wind and solar resources in Pilbara and the large project scale are supposed to result in competitively priced renewable energy with a high capacity factor.

Project development commenced in 2014 with a study of the entire north-west coast of Western Australia. The project land has been secured through the WA Department of Lands, the Traditional Owners are also actively engaged and supportive, onshore and offshore development studies are underway, and a consortium of global renewable energy leaders has been assembled. The West Australian Government, as the Lead Agency, acknowledged the project’s potential and progress in July 2018.

→ “Renewable Hydrogen” in New South Wales (https://www.renewablehydrogen.com.au)

The company vision is for the Australian renewable energy sector to power carbon-free growth, development and energy security throughout the Asia-Pacific region.

Australia is one of the region's leading energy providers and LNG suppliers, and is confident it can meet the region's needs for industrial scale renewable energy supply using hydrogen as the means of storage and bulk transportation. The company plans to export renewable hydrogen in the form of ammonia, i.e. using an established shipping supply chain from the global fertiliser industry.

Beyond Australia, other developed countries are also investing in RD&D of hydrogen technologies. Apart from ammonia as the transport medium, Japan is also testing a patented Liquid Organic Hydrogen Carrier in Brunei. Hydrogen will be produced by steam methane reforming. It will then be mixed with toluene to convert it to methylcyclohexane (MCH), which is liquid under ambient pressure and temperature.

After being shipped to Japan, the hydrogen is then extracted from MCH by a dehydrogenation reaction and deployed as hydrogen gas. This demonstration project is scheduled to be operational for a year, largely used for the 2020 Tokyo Olympics. Around 210 tonnes of hydrogen are expected to be supplied to Japan which could power around 40,000 fuel cell vehicles. Although this project is not using renewable energy sources, it could demonstrate the feasibility of transporting H2 over large distances.

It is noted here that NCCS, Strategy Group, Prime Minister's Office along with the Economic Development Board (EDB) and Energy Market Authority (EMA) are conducting a study specifically on hydrogen imports and possible downstream applications for Singapore. It will assess potential sources of hydrogen imports to Singapore, suitable downstream applications of imported hydrogen, identify R&D opportunities to advance hydrogen technologies in Singapore, and recommend solutions to address hydrogen-related policy and regulatory challenges. The study is expected to be completed in July 2020.

7 Summary of derived needs for increasing PV penetration in Singapore

It is noted here that the comprehensive list of RD&D topics, proposed actions for fostering industrial activities and development, and general recommendations from the 2014 PV Roadmap still apply.

From the work on this Update to the PV Roadmap, the following areas are highlighted due to their large possible impacts for increasing deployment of solar PV and industry development in Singapore.

7.1 High to ultra-high efficiency solar technologies

High to ultra-high efficiency technologies refer to advanced crystalline silicon technologies, such as hetero-junction (HET) and all-back contact (ABC) solar cells up to ~27% efficiency, and future tandem solar cells that can lead the path beyond 30% efficiency.

As discussed in the report, high- and ultra-high efficiency technologies have two major advantages for deployment in Singapore: (i) they increase the space utilisation (more installed capacity on the same area), while not suffering from a lower LCOE, even at a substantial price premium; and (ii) due to their lower negative temperature coefficient, they also convert more sunlight into electricity, hence they also increase the energy yield for the same capacity.

RD&D:

Given the strong PV manufacturing base in Singapore for advanced Si solar cell technologies (REC Solar for HET, Maxeon Solar for ABC), this should be a key focus area of future research directions (i.e. to further evolve the technologies to their practical limits in manufacturing).

For tandem solar cells, the obvious choice is perovskites-on-silicon, where Singapore can take advantage of the fact that it has invested in the past in two major R&D centres, one on perovskites (ERI@N, NTU) and one on crystalline silicon solar cells (SERIS, NUS). The research direction would be on increasing cell efficiencies, increasing durability and reliability, and setting up an industrial pilot line that allows industry-relevant research on perovskites-on-silicon tandem solar cells and modules.

Policy & Regulations:

Future government tenders (e.g. as part of the SolarNova programme) should specify solar PV installations with a higher system efficiency or area factors.

At the same time, such tenders should call for higher Performance Ratios (PR), which then also increases the energy yield. Initial PR values of >80% have been achieved by many industry players, with two systems developed and installed by SERIS even reaching 90% (at not significantly higher cost).

7.2 Novel "urban solar" applications

There is great potential to develop cost-effective solutions in certain areas where Singapore has a good deployment potential and where there are no off-the-shelf solutions available in the global market.

RD&D:

As discussed in the report, the following areas are very promising:

- Rooftop PV (e.g. standardised "plug & play" solutions for rooftops and facades; co-locations of PV with greenery)
- BAPV / BIPV (e.g. coloured BIPV modules; pre-fabrication of BIPV; "transparent" PV windows; ultra-light BIPV elements; and PV-powered media walls)
- Mobile-/land-based PV systems (e.g. easy-to-(re)deploy PV systems, mobile sub-stations)
- Floating PV (maritime-proven systems, combination with other uses such as fish farming, hydrogen generation or desalination)
- Infrastructure PV (cost-effective structures over-arching land, canals, roads; or PV noise barriers)

Solutions developed, tested and deployed in Singapore would equally be useful in other megacities that want to increase their PV deployment, leading to possible export opportunities.

Policy & Regulations:

Many of these developments can be fostered by an encouraging environment, such as agencies allowing test-bedding (e.g. PV noise barriers) and opening opportunities for deployment of the novel technologies (e.g. allocating specific areas for land-based or infrastructure PV).

Given the vast potential for solar PV on rooftops and facades in Singapore, further encouraging or mandating solar PV on buildings could be an option, e.g. through increasing the green mark (GM) points (absolute and relative) for the adoption of solar PV on rooftops or facades. This would also support the SLE/ZEB/PEB building agenda of BCA.

In addition, a new Singapore "Best Solar Architecture" award could be created, which should trigger a city-wide competition amongst architects and developers, for aesthetically and technically advanced implementation of PV in the built environment.

7.3 PV grid integration

As shown in the report, at higher PV penetration rates the power system in its current form may not be able to handle the generation pattern from solar PV anymore. This is not of immediate concern, but needs to be addressed early to have solutions ready by the time they are required.

RD&D:

Main areas identified for mitigating the possible impact of variable solar generation are:

- Operational solar forecasting (on different time horizons from 5 min to 24 hours)
- Demand response (e.g. as one possible alternatives to reserve power)
- Energy storage systems (e.g. with a focus on fast-response systems, and the combination of electrical and thermal storage such as in district cooling plants)
- Smart inverters and power electronics (that allow for provision of substantial amounts of ancillary services, despite the highly distributed nature of the PV systems in Singapore)

Policy & Regulations:

Given the high variability of solar generation and the possibility of extreme events in Singapore, the "non-solar" assets in the power system must be able to handle any high variability situations. This may have two aspects that would need to be further assessed in the future:

- There might be a need for a capacity-based market system that is adequately priced to incentivise substantial stand-by reserves.
- The dispatch cycle may need to be shortened from the current 30 min. Other countries with high variable renewables such as Australia (wind and solar) are exploring even 5 min dispatch cycles.

7.4 Other topics of increasing relevance for Singapore

7.4.1 Recycling and Circular economy

As discussed in the report, there is a need to address recycling of PV from both an RD&D and Policy & Regulations perspective. Aspects to be addressed include:

- On-site recycling (currently the scrap value of the PV system typically does not cover the cost of transportation to a central recycling facility)
- Development of cost-effective recycling solutions (in particular using less thermal processes, which otherwise worsen the CO_2 balance of the PV system)
- Moving towards a circular economy (which is still in infancy for the PV industry; however, a light-weight, mobile system as proposed under novel urban applications above could be a first step in that direction).

7.4.2 Urban Heat Island effect of PV in cities

Whilst it is important to focus on urban planning strategies, also architectural design innovations and engineering solutions must be understood, which prioritise and optimise solar energy harvesting, the associated social, economic and environmental impacts of large scale solar development in the city as a whole. This is particularly true for the Urban Heat Island (UHI) effect.

To this end, a comprehensive city-wide database of solar potential and knowledge base of solar development could be created that taps into, and builds on top of, the existing information infrastructures across the lead agencies in various urban administration domains. Such an integrated platform could support and facilitate a) investigation on innovative urban solar solutions for researchers, b) efficient PV deployment for solar developers, and c) informed policy making on renewable energy for government agencies.

7.4.3 Bankability of PV in Singapore

Solar electricity, when exported to the grid, cannot be pre-dispatched and is therefore a price-taker in the wholesale electricity market where prices are determined by bids from dispatchable conventional power sources, mainly gas-fired CCGT. This exposes solar developers to long-term "merchant risk" (i.e. the price fluctuations in the conventional power market). This leads to a lower appetite for project financing amongst lenders in Singapore, especially for non-recourse financing, which would solely be based on the future cash flows of the generating assets.

To unlock the large amounts of green financing that in-principle is available in Singapore, two possible ways could be: (i) contracts for difference (CFD); and (ii) using the large real-estate base as collateral.

For (i), as a benchmark, CfD is the main mechanism for supporting low-carbon electricity generation in the UK. CfDs incentivise investments in renewable energy projects with high upfront costs and long lifetimes by protecting developers from volatile wholesale prices, and consumers from paying increased support costs. Successful developers of renewable projects enter into a private law contract with the Low Carbon Contracts Company (LCCC), a government-owned entity. Developers are paid a flat (indexed) rate for the electricity they produce over a 15-year period, which is derived from the difference between the 'strike price' (a price for electricity reflecting the cost of investing in a particular low carbon technology) and the 'reference price' (a measure of the average market price for electricity in the GB market). This form of contract, therefore, provides price certainty for the developer, which should raise the project's appeal to banks and other investment finance institutions.

For (ii), a previous study[1] tried to apply three innovative types of financing mechanisms commonly practiced for the US, to the case of Singapore. The financing models investigated are:

- PACE (property assessed clean energy);
- WHEEL (warehouse energy efficiency loan); and
- OBF/OBR (on-bill financing, on-bill repayment).

The paper also discussed the opportunities and hurdles for Singapore. Adopting such innovative financing schemes would require a public-private partnership with a number of government agencies involved, but could lead to highly innovative financing schemes.

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[1] M. Bieri, R. S. Baker, S. Tay, T. Reindl, Proceedings of the 32nd European Photovoltaic Solar Energy Conference and Exhibition (EU PVSEC), Munich 2016, pp2997-3002.

ANNEXES

A Overview of current policies and regulations for solar PV in Singapore

The approach of the Singapore government to promote sustainable energy can be summarised as follows:

- Right Pricing:
  Pricing energy right incentivises efficient use of energy and avoid wasteful consumption. There are no subsidies for renewable energy nor for conventional energy sources, and implementation of a carbon tax in 2019 will put a price on negative externalities that fossil fuels impose on the environment. Given the intermittent nature of solar, the Intermittency Pricing Mechanism (IPM) will be implemented around 2020 to allocate the costs of reserves fairly across all generation types and promote the price signal to encourage investment in measures to manage intermittency.

- Progressive Regulations:
  The relevant agencies will continue to review, streamline, and enhance the existing regulations and processes to facilitate solar deployment.

- Catalysing Demand:
  The public sector is taking the lead in adopting solar energy, through initiatives such as the SolarNova programme, which aggregates public sector demand for solar PV.

- Research and Development:
  The government partners with industry and the research community to test-bed solutions that will enable us to better manage the intermittency challenges posed by renewables. This will allow us to accommodate more renewables in our energy mix while maintaining system stability and reliability.

In terms of current regulations, the types of payment schemes available to developers are summarised in Table A.1. A few regulatory enhancements have been introduced in 2017 to facilitate the deployment of distributed solar PV systems in Singapore, most notably the inclusion of the "Enhanced Central Intermediary Scheme" or ECIS.

Under the ECIS, each eligible contestable consumer is not required to register with the EMC as a Market Participant to get paid for injecting any excess EG[1] output into the grid. The payment will be through SP Services at the prevailing half-hourly wholesale energy price. This helps encourage the installation of more distributed systems to the benefit of Singapore's highly urbanised landscape.

The Solar Generation Profile (SGP) was further introduced in 2018, which aims at reducing metering costs for PV systems owners. It targets both IGS[2] consumers registered with EMC and participants under the ECIS scheme. The purpose is to estimate gross solar generation based on a fixed profile (instead of being measured by a so-called "M1" meter) for calculating

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[1] EG = Embedded Generation.
[2] IGS = Intermittent Generation Sources.

the settlements of market charges. This also benefits smaller systems, which will have one meter less to install.

Consumers who opt for the SGP will have their IGS generation (kWh) estimated based on the installed capacity of their IGS installation and the SGP determined by EMA. The SGP is derived based on factors such as the historical average solar irradiance in Singapore, from 7am – 7pm, and will be standardised for all IGS installations throughout the year.

Table A.1: Regulations and types of payment schemes available to solar PV developers in Singapore (as of January 2020). Source: EMA.

Type of payment scheme	System size	Details
Simplified Credit Treatment Scheme (SCT)	< 1 MWac	Non-Contestable Consumers (NCC) to directly register with SP Services. NCCs that sell any excess energy to the market will be paid at the prevailing regulated tariff minus grid charges.
Enhanced Central Intermediary Scheme (ECIS)	< 10 MWac	Contestable Consumers (CCs) can register with SP Services directly, reducing regulatory barriers and administrative matters. CCs that sell any excess energy to the market will be paid at the prevailing half-hourly wholesale energy prices (USEP).
Market Participant (IGS Non-Exporting)	< 10 MWac	Consumers with no intention to export are not required to provide credit support or to submit generation meter readings to EMC. Consumers will not be paid for injecting any excess energy to the grid. Consumers are required to pay EMC an estimated fixed charge on the IGS capacity every six months. This will be based on a standardised IGS Generation Profile for all consumers.
Market Participant (exporting)		Consumers need to register as a Market Participant with EMC, subject to the relevant Market Rules. Any excess solar energy sold back to the market will be paid at the respective nodal price.

In addition, Singapore has also introduced a carbon tax, which came into operation on 1 January 2019. Any industrial facility that emits direct GHG[1] equal to or above 25,000 tCO_2e annually will be required to be registered as a taxable facility and to submit a Monitoring Plan and an Emissions Report annually. Taxable facilities will be liable for carbon tax from 1 January 2019 onwards for reckonable GHG emissions. The carbon tax is set at a rate of SGD 5 per tonne of GHG emissions (tCO_2e) from 2019 to 2023. Singapore will review the carbon tax rate by 2023, with plans to increase it to between SGD 10 and SGD 15 per tonne of GHG emissions by 2030 (NEA). While this does not impact solar adoption directly, it does marginally increase the cost of electricity generation for natural gas and other thermal plants in Singapore. This, in turn, might make solar energy more competitive in the future.

[1] GHG = Greenhouse Gases

B LCOE methodology and assumptions

The levelised cost of electricity (LCOE) is a well-established method in energy finance and policy for the calculation of the cost of electricity generation at the point of connection (to a load or the electric power grid). The LCOE is calculated by dividing the entire lifecycle cost of a solar PV system by its cumulative solar electricity generation. It is presented in net present value terms, with each year's cost discounted by the investor's hurdle rate.

While a LCOE gives a monetary value per unit of electric energy generated by a certain technology, external factors or costs associated with grid integration are not taken into account and must be considered separately. In the case of PV, such external factors can be "negative" costs (e.g. reduced conventional capacity required due to matching peak generation with peak demand) or "real" costs (e.g. potential need for energy storage to bridge sudden generation losses caused by cloud-reduced solar irradiance).

The LCOE (before tax) formula used in this analysis is shown in Equation 1.

$$LCOE = \frac{EPCI + \sum_{n=1}^{N} \frac{OM^* + IC^*}{(1+DR)^n} + \frac{IEI^*_{n=5,10,15,20}}{(1+DR)^{n=5,10,15,20}} + \sum_{n=1}^{N} \frac{LP}{(1+DR)^n}}{\sum_{n=1}^{N} \frac{(IRD \times PR) \times (1-SDR)^n}{(1+DR)^n}} \qquad \text{(Equation 1)}$$

**Inflation adjusted*

Where:

EPCI	= Equity project cost investment
IC	= Insurance cost
N	= Number of years in the system's service life
OM	= Operation and maintenance
DR	= Nominal discount rate
IEI	= Inverter warranty extension investment
LP	= Loan payment
IRD	= Irradiance
PR	= Performance ratio
SDR	= System degradation rate

The numerator sums up all the possible cost items over the system's entire lifetime. The investment cost comprises the equity project cost investment (EPCI). The annual operating cost is split in two parts, namely the operating and maintenance cost (OM) and the insurance cost (IC). The inverter warranty extension investment (IEI) represents the warranty extension cost for the systems' entire operating life. The year in which the warranty is extended depends on inverter suppliers. The model assumes a warranty extension at years 5, 10, 15, and 20. In case a part of the upfront CAPEX is debt financed, the loan payments (LP) include annual interests and amortisations. The denominator includes the system's lifetime electricity generation. The specific yield is the energy yield of the system in the first year, which is calculated by the product of the available irradiance (IRD) and the performance ratio (PR). After the first year, the generation output is annually adjusted according to the system degradation rate (SDR). OM, IC, and IEI are adjusted with the inflation rate after the first year.

Both values, the numerator and denominator, are discounted by the nominal discount rate (DR) for net present value calculations, which is based on the weighted average cost of capital (WACC) concept (see Equation 2).

$$WACC = (1-D)\times(RFR_{20} + b\times MRP) + D\times(RFR_{10} + DP)(1-TR) \qquad \text{(Equation 2)}$$

Where:

- Local risk free rates (RFRs) are based on Singapore's government bond yield data, 10 years for the debt cost (RFR_{10}), 20 years for the equity cost (RFR_{20});
- For the cost of equity, a beta (b) of 1.0 was applied, assuming an investment of a solar system bares equal risks as investing in the economy of Singapore;
- For the Market Risk Premium (MRP), the latest available figure (6.53%) from EMA was used[1];
- D = debt ratio (percentage of investment financed by an external lender as opposed to 100% equity financing) and DP = debt premium; see inputs parameters in the table "Financial metrics" below;
- The Tax Rate (TR) applicable for corporate incomes in Singapore was used (i.e. 17%).

The assumptions used for the various components that allow the calculation of the LCOE are summarised in Table B.1. All forecasts (2020-2050) are provided in constant 2019 SGD.

Table B.1: CAPEX, OPEX, Energy output and Financial metrics assumptions used for LCOE calculations.

CAPEX
All system costs include development costs, construction insurance and a margin for profit for system integrators. To remain conservative and given the high uncertainty level in forecasting costs for the longer term, no more equipment and BOS cost reduction is considered after 2040 (BOS cost reduction is also no longer considered after 2030 for rooftop and ground-mounted PV applications).
Modules considered for cost projections are high efficiency modules, i.e. mono-Si PERC with power output higher than 300 W. Due to space constraints, low efficiency modules (i.e., multi-Si module lower or equal to 300 W) are no longer considered in the context of Singapore. PV module floor cost throughout the forecast period is set at USD 0.10/Wp.
Inverter floor cost throughout the forecast period is conservatively set at USD 0.025/Wp for central inverters and USD 0.035/Wp for string inverters.
Floating structure floor cost (including anchoring and mooring) throughout the forecast period is set at USD 0.08/Wp.
Capex does not include grid connection and transmission costs as these can vary substantially from one location to another and are therefore difficult to generalise.
No residual value and decommissioning costs have been considered as it was simplistically assumed they balance each other.

OPEX
No rental cost to building/space/reservoir owner is included.
O&M costs vary between 1-1.45% of capex, depending on the type of system (1% for large rooftop compared to 1.45% for smaller systems). As capex is decreasing over time, so is O&M assuming improvements brought by smart O&M.
Annual operating insurance cost is estimated between 0.4 and 0.6% of capex.

[1] Review of the Long Run Marginal Cost Parameters for Setting the Vesting Contract Price for 2019 and 2020, Final Determination Paper (26 November 2018)

Energy output
Assumed a constant P50 annual irradiance of 1,644 kWh/m^2 throughout the forecast period, which is based on empirical figures from National Environment Agency (NEA), monthly data from 1991-2000 and 2010-2018 at Changi Meteorological Station (S24).
The PR is starting at 78% and improving by 0.5% per year until reaching a ceiling of 82% for mono-Si PERC modules. Floating PV (FPV) systems are assumed to have a 6% PR increase over rooftop and land-based PV applications.
Annual system degradation rate remains constant throughout the forecast period and is assumed as follows: • 0.8% for rooftop and land-based PV systems • 1% for FPV on inland reservoirs • 1.5% for FPV near-shore

Financial metrics
Loan tenure: 10 years (for all PV applications).
Depreciation: 25 years straight-line.
System lifetime: 25 years.
Inflation on OPEX: 1.7%.
Taxation: zero, i.e. calculation is excluding taxes.
No interest during construction, assuming lenders offer a grace period.
Fixed exchange rate throughout the forecast period: SGD:USD = 1.36 (based on average SGD:USD exchange rate between 2007 and July 2019).
Nominal debt rate (all-in): 5% (risk-free rate of 1.92%[1] and debt premium of 3.08%).
Cost of equity: 8.75% or ~9% (risk-free rate of 2.22%[2], market risk premium of 6.53%[3] and beta of 1.0).
With regards the gearing ratio, two extreme financing scenarios have been considered, which constitute a lower and upper limit of the LCOE result range for each solar PV application: • 100% debt-financed with WACC = 5%. • 100% equity-financed with WACC = 9%.

Capex forecasts have been aligned with BNEF forecasts (1Q 2019) until 2025 and ITRPV 10th edition (March 2019) until 2029. The LCOE results have been further benchmarked against the EIA LCOE - Annual Energy Outlook (February 2019) until 2040.

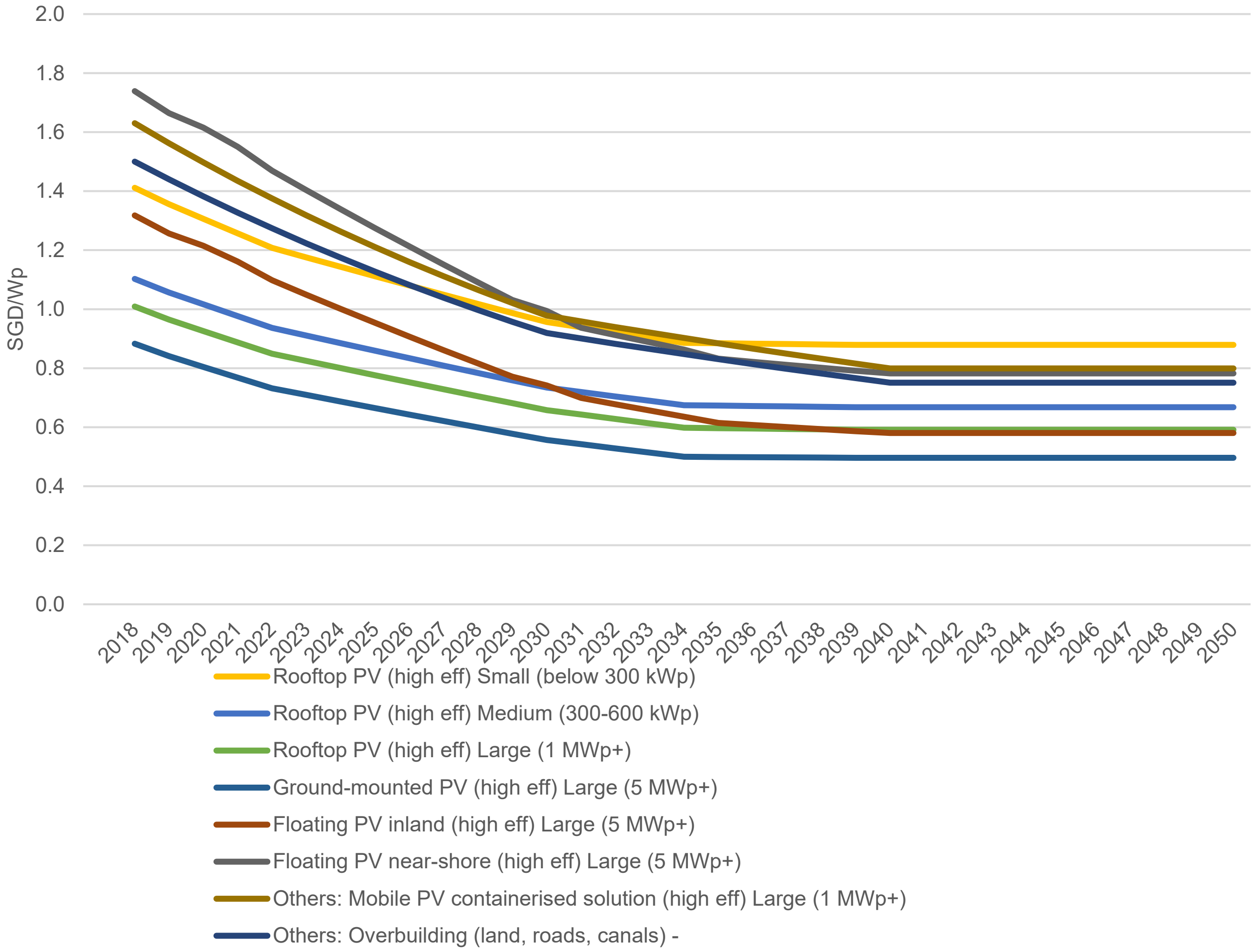
Capex was projected until 2050 for various solar PV application types, as shown in Table B.2.

Table B.2: Type of PV system applications used in the LCOE calculations.

PV system application	Typical size
Rooftop	Residential 1 (3 kWp)
	Residential 2 (25 kWp)
	Residential 3 (50 kWp)
	Commercial small (below 300 kWp)
	Commercial medium (300-600 kWp)
	Industrial (1 MWp+)
Ground-mounted	Large (5 MWp+)
Floating PV inland	Large (5 MWp+)
Floating PV near-shore	Large (5 MWp+)
Others: Mobile PV containerised solution	N/A
Others: Overbuilding (land, roads, canals)	N/A

[1] Average monthly yield of 10-year Singapore Government Securities as of July 2019.
[2] Average monthly yield of 20-year Singapore Government Securities as of July 2019.
[3] From EMA, Review of long run marginal cost parameters for setting the vesting contract price for 2019 and 2020: Final determination paper (26 November 2018).

By 2050, capex is expected to reduce by about 45% compared to 2019 (see Figure B.1). Large ground-mounted PV, rooftop PV (1 MWp+) and floating PV inland systems are expected to have the cheapest installed costs. However, these figures exclude any grid connection cost, which might be required for ground-mounted or floating PV systems if large systems are constructed further away from the main grid or if new substations need to be built.



<u>Figure B.1:</u> 2019-2050 Capex forecasts for different PV applications in Singapore.

The current LCOEs and projections for 2030 and 2050 are summarised in Table B.3, based on a WACC (weighted average cost of capital) of 5% and 9% to illustrate two different financing alternatives available to PV system owners. The lowest LCOE is achieved for ground-mounted PV installations, closely followed by large rooftop PV (>1 MWp). Future changes in deployment cost will also affect the LCOE. For example, LCOE for Floating PV on reservoirs is expected to become the second-lowest cost option after 2030.

Table B.3: LCOE projections for different WACCs (weighted average cost of capital).

LCOE (in SGD cents/ kWh)			**2019**	**2030**	**2050**
@ WACC 5%	Rooftop PV	Very small 1 (3 kWp)	15.62	10.81	9.96
	Rooftop PV	Very small 2 (25 kWp)	13.37	9.09	8.39
	Rooftop PV	Very small 3 (50 kWp)	12.73	8.68	7.90
	Rooftop PV	Small (below 300 kWp)	11.36	7.76	7.19
	Rooftop PV	Medium (300-600 kWp)	8.56	6.11	5.24
	Rooftop PV	Large (1 MWp+)	7.57	5.00	4.49
	Ground-mounted PV	Large (5 MWp+)	6.50	4.24	3.82
	Floating PV inland	Large (5 MWp+)	9.69	5.58	4.44
	Floating PV near-shore	Large (5 MWp+)	13.36	7.69	6.07
	Others: Mobile PV containerised solution	Large (1 MWp+)	11.69	7.13	5.94
	Others: Overbuilding (land, roads, canals)	-	10.91	6.77	5.65
@ WACC 9%	Rooftop PV	Very small 1 (3 kWp)	19.40	13.35	12.24
	Rooftop PV	Very small 2 (25 kWp)	16.81	11.39	10.47
	Rooftop PV	Very small 3 (50 kWp)	16.03	10.87	9.89
	Rooftop PV	Small (below 300 kWp)	14.30	9.71	8.97
	Rooftop PV	Medium (300-600 kWp)	10.86	7.25	6.61
	Rooftop PV	Large (1 MWp+)	9.69	6.36	5.71
	Ground-mounted PV	Large (5 MWp+)	8.35	5.39	4.83
	Floating PV inland	Large (5 MWp+)	12.30	7.04	5.57
	Floating PV near-shore	Large (5 MWp+)	16.85	9.66	7.61
	Others: Mobile PV containerised solution	Large (1 MWp+)	15.15	9.18	7.60
	Others: Overbuilding (land, roads, canals)	-	14.09	8.69	7.21

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