Huangpu Economic Development Zone Guangzhou, China Industrial Rooftop Solar Photovoltaic Power Program Technical Implementation Document

December 2018
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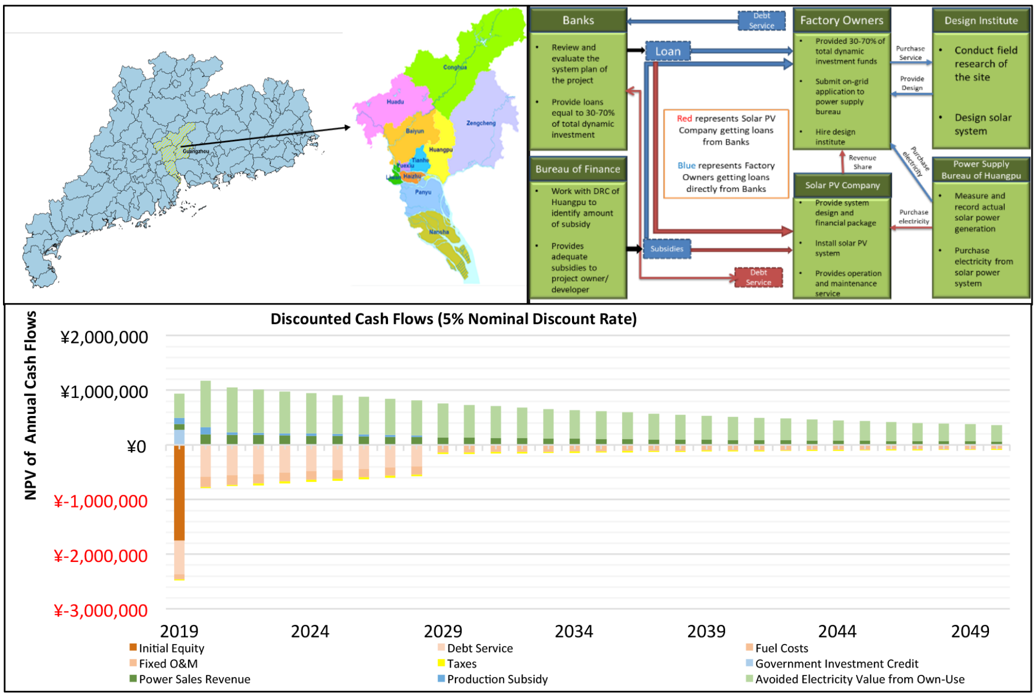

Industrial Rooftop Solar PV Program – Huangpu EDZ

This Technology Implementation Document (TID) documents the details for implementing an industrial rooftop solar photo-voltaic (PV) program in the Guangzhou Economic and Technological Development Zone located in the Huangpu District (Huangpu EDZ). It contains an Implementation (or business) model, as well as documentation of a financial analysis and the expected impacts of the program. It was developed by the Global Environmental Institute (GEI), the Guangzhou Institute of Energy Conversion (GIEC), and the Center for Climate Strategies (CCS). The development team would like to thank the Guangdong Solar Energy Industry Association for their review and input to this document.

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Technology Application Description

A local resource assessment for the Huangpu EDZ conducted by the research team with input from a local expert group on solar power identified industrial rooftop PV applications to have the highest priority for implementation. From the local resource assessment, the technical potential for industrial rooftop solar PV in the Huangpu EDZ was estimated to be 505 mega-watts (MW).[1] Therefore, this TID focuses on an implementation (or business) model for implementation of industrial rooftop PV systems. The Huangpu district has planned to install 302 MW solar PV capacity in any form across all building sectors by 2020. However, there has been limited progress on the implementation of this technology. The current installed capacity is less than 50 MW as of 2015. Under BAU conditions, the project team estimates that the total installed capacity of solar PV will be 185 MW by 2020 (these represent installations after 2015, including those in the development pipeline through 2020). Even if all of this BAU capacity was installed on industrial rooftops, an additional technical potential of 320 MW is available based on our local area assessments. Considering the implementation period included for this program (through 2025), if the program is successfully implemented according to the Business Model, it will tremendously help the Huangpu district to achieve its existing solar PV installation target by 2020 as well as additional capacity through 2025.

There are at least three basic ways that industrial rooftop solar PV systems can be configured. The first, and most common in nations where electricity grid systems are well-established, is a grid-connected configuration where PV panels either provide power directly to the grid, and the industrial facility purchases power back from the grid to meet daily needs, or where solar PV power goes first to meet the needs of the facility, and any excess is sold to the grid. In either case, the electricity grid provides power during those times when there is insufficient electricity production by the PV system to meet facility needs. The second type of system is a grid-independent or "off-grid" system, where PV power is used for industry needs but also charges a battery or other energy storage device, to be drawn upon when direct power from the PV system is not available or insufficient. The third type of system can be thought of as a hybrid, whereby a number of facilities share a PV system and share electricity/energy storage in a "micro-grid" configuration, which may be supplemented by a non-solar power source, such as a gas turbine or diesel engine-generator, and/or supplemented by some imports of grid power. In the Huangpu EDZ, in which all industrial facilities are likely connected to the electrical grid, the first and third of these options are likely to be the most practical.

For the Huangpu EDZ Program, the projects themselves will be at the individual facility or building scale. Individual projects will be targeted to one or more types of markets for industrial solar PV in the Huangpu EDZ. Differentiation of markets could be by industry subsector or size, existing or new facilities, own use of power generated or for sale to the grid or a combination of the two, and location within the EDZ. Based on geographic information system (GIS) – based sampling of industrial rooftops in the Huangpu EDZ, the largest PV system sizes are expected to be on the order of 8 MW, although more typical sizes will be in the 1.5 MW size range. Assuming all systems would be of this size, over 200 PV systems would be addressed by the program.

Note that as a result of the financial analysis provided toward the end of this document, the market potential of the program is not expected to reach the full technical potential of 320 MW identified by the team. This results from a reduction in government subsidies for solar power provided to the grid in line with the provincial government's plan to pay the same rate as conventional power sources (e.g. coal). The most financially-attractive projects will be those where a large fraction of the power generated is for own-use during periods of peak or intermediate demand (thereby avoiding more costly retail electricity rates).

Potential sources of finance range from funds provided by each industrial facility owner (equity); to private bank financing (debt); enabling mechanisms, such as utility or government rebates; and/or funds from carbon trading systems. Combinations of these types of financing are likely, and the technology application design and implementation model described below includes the two most likely:

1) solar PV company applies for loans from bank and then provides both installation and financing to the factory owner; or

2) factory owners apply directly to the banks for loans and contract separately with the solar PV company.

Note that for the first option, it is also possible that a solar PV manufacturer offers systems, installation, and financing directly to factory owners. The financial analysis towards the end of this document covers a range of system sizes and the most likely form of project financing – the second option identified above.

1 Renewable Energy Implementation Toolkit: Development and Testing in South China, prepared by the Center for Climate Strategies, Guangzhou Institute of Energy Conversion, and the Global Environmental Institute, November 2017; http://www.climatestrategies.us/library/library/view/1222. Since publication of the previous estimates of technical potential, the Team has continued to monitor the development of solar systems in the Huangpu EDZ. Current installed capacity is less than 100 MW as of 2017. The high end of technical potential could be as high as 420 MW may be available; however, the analysis of the program adopts the previous lower end of the range in estimated technical potential of 320 MW.

Technology Application Design and Implementation

Goals

The Huangpu Industrial Solar PV Program will implement up to 320 MW of solar power generation on industrial facility rooftops through the economic development zone.

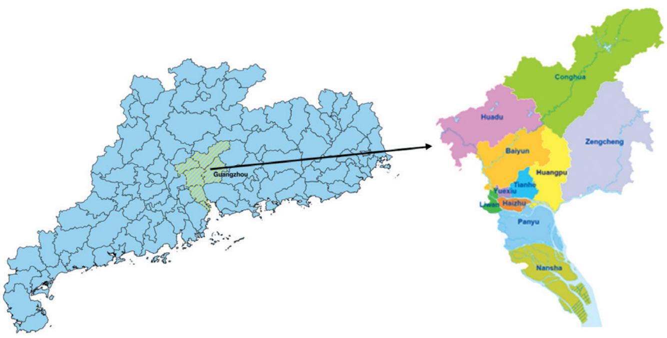
Location

Industrial rooftops throughout the Huangpu EDZ. Figure 1 provides an overview of the EDZ.

Timing

The Program will run from 2018 – 2025. Industrial rooftop PV installations will total 117 MW by 2020 and 320 MW by 2025.

Figure 1 Map of the Huangpu EDZ



The map below shows the location of the Huangpu EDZ within the city of Guangzhou, Guangdong Province.

Business as Usual (BAU) Programs and Other Related Information

The timing for installations above recognizes that opportunities exist for new industrial buildings being constructed as part of the Sino-Singapore Knowledge City in the northern portion of the EDZ, as well as existing industrial roof space in the southern portion (especially the Yunpu Industrial Park).

Expected business as usual (BAU) installations of PV systems in the EDZ are 185 MW by 2020. Most of this capacity has been built within the industrial sector. Of this expected capacity in 2020, 72 MW were installed by 2016 and another 113 MW are estimated to be in the development pipeline. The Program goals represent installations expected above and beyond BAU installations up to the estimated technical potential for industrial rooftop solar PV estimated from the local area supply assessment (505 MW). This includes about 117 MW of industrial rooftop solar PV by 2020 (320 MW including BAU installations) and another 203 MW by 2025 (505 MW total including BAU installations).

The total Huangpu EDZ program is 320 MW of capacity above and beyond BAU by 2025. The largest areas for installations within the Huangpu EDZ are the Sino-Singapore Knowledge City (155 MW) and the Yunpu Industrial Park (70 MW). At an estimated median size of 70 kW per system, the total program will address over 5,000 individual projects (note that a single industrial facility may have multiple projects). The Project Team recognizes that 505 MW of technical potential represents an upper bound of industrial rooftop PV potential, since this value has not yet been corrected for shading or technical feasibility of installations on all industrial rooftops.

Implementation Model

The Implementation Model (sometimes also referred to as the "business model") for the Program is summarized in Table 1 below. The Implementation Model is divided into 7 phases. Within each phase, the discrete steps (legal, policy, administrative, and financial mechanisms) that need to be addressed by a specified party are also listed. Additional details on the implementation phases are provided in the section below. More details are provided for the Implementation Model in the next section. Regarding financial mechanisms, these are summarized in the Financial Model shown in Figure 2 below.

The Implementation Model for projects in the Huangpu EDZ Industrial Rooftop PV Program features two different financing strategies. From the perspective of a factory owner, Financial Strategy 1 represents the simplest option. In Financial Strategy 1 (red), the solar PV company obtains loans from a bank and then provides all services directly to the factory owners (design, installation, follow-on O&M). In financial Strategy 2 (blue), factory owners obtain bank loans, and then contract separately for system design and system installation/O&M. The Power Supply Bureau of Huangpu would purchase power supplied to the grid from either the factory owner or solar PV company, depending on the financial strategy used.

Parties Involved

Parties included in the Implementation Model include GIEC, GEI, the Huangpu Development and Reform Bureau (HPDRB), lending institutions, industrial facility owners, the Power Supply Bureau of Huangpu, China Southern Grid, and project developers. The specific role of each is specified in each step of the Implementation Phases of the business model presented above.

Figure 2 Huangpu EDZ Industrial Rooftop PV Program Financial Strategies.

The Business Model features two different financing strategies. In financial strategy 1 (red), the solar PV company obtains loans from a bank and then provides all services directly to the factory owners (design, installation, follow-on O&M). All power not used directly by the facility ("own-use") is sold directly to the grid operator and a revenue sharing agreement is made between the factory owner and solar PV company. In financial strategy 2 (blue), factory owners obtain bank loans, and then contract separately for system design and system installation/O&M. The local power utility purchases excess power for the grid from the factory owner in financial strategy 1.

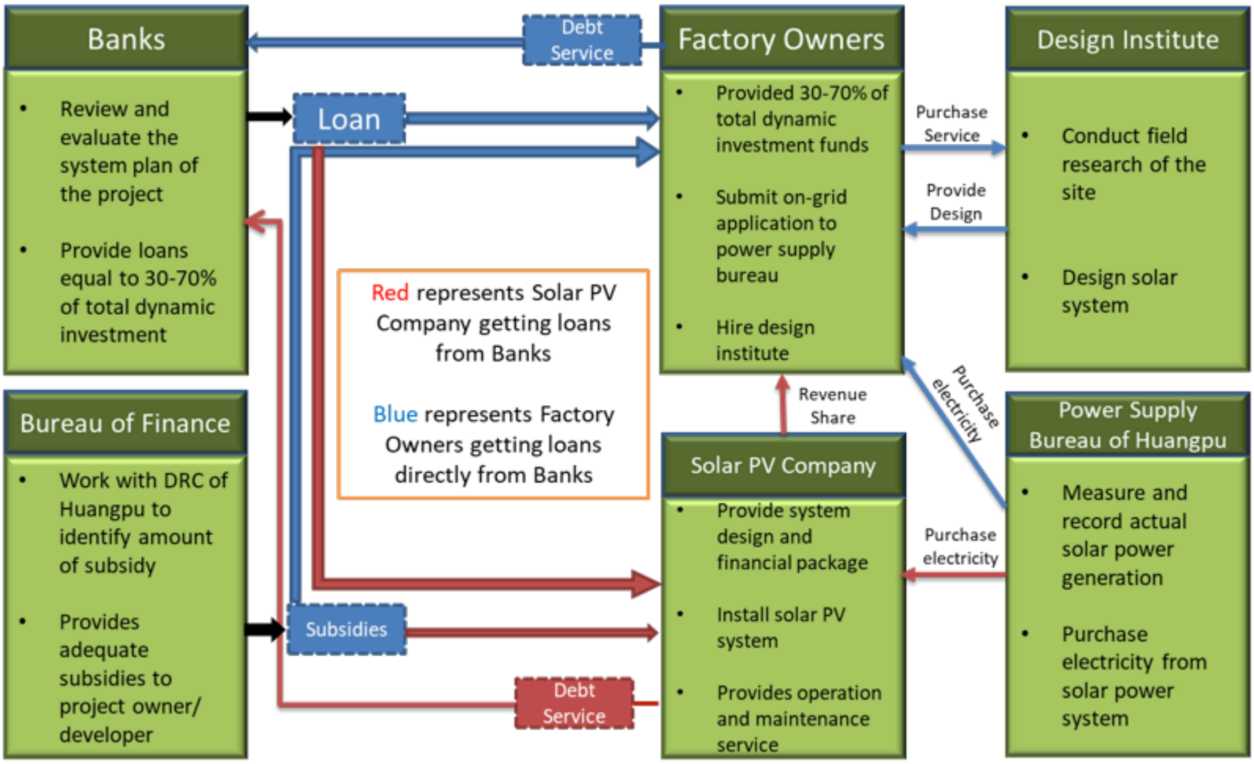


Table 1. Implementation Model for the Huangpu Industrial Rooftop Solar PV Program

Phase	1	2	3	4	5
Phase Name	Complete Program Feasibility Assessment	Partner Assembly	Program Marketing to Industry	Define and Aggregate Projects	Program Marketing to Lenders
Parties Involved	• GIEC • Huangpu Power Supply Bureau (HPSB) • China Southern Grid (CSG) • Huangpu DRB • Industrial Facility Owners	• GEI • GIEC • Industrial Facility Owners • PV Project Developers • HPSB, CSG • Lending institution(s) • HPDRB	• PV Project Developers • Industrial Facility Owners	• Project Developers • Industrial Facility Owners	• Lending Institution(s) • Industrial Facility Owners • PV Project Developers
Steps: Legal, Policy, Administrative, and Financial Mechanisms	1. GIEC works with HPSB and CSG to assess technical feasibility of integrating the levels of new distributed generation achieved by the program. 2. GIEC, HPSB, and CSG address any identified feasibility issues. 3. GIEC leads presentation of the Program to HPDRB; and acceptance of the Program by HPSB, CSG, and local agencies.	1. Huangpu DRB convenes a workshop in Guangzhou to introduce the Program to all potential partners; GIEC presents the Program and its expected impacts to each partner and gains their support for the program and agreement on their role, timing, etc. 2. Project developers prepare a standard financing package(s) to market to facility owners.	1. PV Project Developers conducts the marketing of the program to facility owners with support from GIEC and project developers. 2. GIEC and Project Developers provide support to interested facility owners to understand the benefits of the program.	1. Industrial Facility Owners issue requests for proposals to Project Developers to design and build their PV system. 2. Project Developers provide proposals to Facility Owners. 3. GIEC provides technical support to Facility Owners to evaluate proposals. 4. Facility Owners select a winning bidder among the proposals submitted (contingent on receipt of funding)	1. GIEC provides support to Facility Owners to understand the financing package. 2. Facility Owner completes and signs the financing package and sends it to Lending Institution. 3. Lending Institution reviews and conducts any follow-up with Facility Owner and Project Developer. 4. Depending on Financial Strategy, either the Project Developer or Facility Owner signs lending contract(s). 5. Lending Institution provides funds to Project Developer or Facility Owner consistent with contract requirements.

Phase	1	2	3	4	5
Analytical Requirements	• GIEC: Detailed local industrial electricity demand, building structure feasibility assessment, and solar PV supply assessment. • HPSB and CSG: Integration assessment of new solar power with the local grid, including reliability issues.	• GIEC: Additional financial analyses for projects of different types (e.g. based on size, inclusion of tracking or storage systems; alternative PV power revenue schemes).	• GIEC develops a listing of industrial facility contacts for marketing the program.	• Project Developers develop preliminary design and cost estimates for use in their proposals to Facility Owners. • GIEC and project developers provide technical assessments of rooftop PV systems for Industrial Facility Owners, including financial analyses, based on site-specific configurations and costs	• Facility Owner reviews any revisions to design and cost proposals from the project developer in response to lender requirements. • Project Developer or Facility Owner revises the financial analysis based on final lending terms (for inclusion in the financing package, as needed).
Other Requirements	• The first bulleted item above will provide an understanding of the amount and timing of power available for provision to the grid (versus that for own-use)	• Lenders: Lenders should provide input on required financial metrics needed to secure funding for individual projects and/or packaging projects for securitization.			

Table 1. Implementation Model for the Huangpu Industrial Rooftop Solar PV Program (cont.)

Phase	6	7	8	9	10
Phase Name	Program Implementation	Program Scale-Up			
Parties Involved	• Industrial Facility Owners • PV Project Developers • HPSB • GEI	• GEI • GIEC • Guangzhou DRC • Guangdong Province DRC (GDRC) • CSG • Industrial Facility Owners • Project Developers • Lenders			
Steps: Legal, Policy, Administrative, and Financial Mechanisms	1. Project Developers install PV systems for Facility Owner 2. Project Developers work with HPSB to tie systems into the distribution grid 3. GEI monitors progress of the program via surveys, including field checks, of facility owners	1. GEI and GIEC prioritize other local areas for industrial solar PV programs and present to Guangzhou DRC or GDRC and CSG to discuss feasibility issues 2. Repeat Program Phases 2 – 6 for each prioritized local area			
Analytical Requirements	• GEI provides monitoring reports on system installations and associated power production for own-use and supply to the grid	• Provincial assessment of industrial rooftop area available at the town/district level. • Prioritization process for Program implementation in other local areas.			
Other Requirements					

A description of each of the Phases and its Steps follows:

Detailed descriptions of each Phase and Step will be further augmented in a separate phase of this project following initial meetings with HPDRB, Solar Industry Representatives, and other local government officials.

1. Complete Program Feasibility Assessment –

a. GIEC identifies the concentrated area that needs to install solar PV. In the target area, they are the Sino-Singapore Knowledge City and Yunpu Industrial Park.

b. GIEC works with the Huangpu Power Supply Bureau and administrative entities of the target area (aka Management Commission of Sino-Singapore Knowledge City and Yunpu Industrial Park) to identify the technical feasibility of the anticipated additions of solar PV to the grid.

c. GIEC/HPSB/CSG: update the estimates of technical potential with technical feasibility in the target area.

d. GIEC and HPSB conduct an assessment of economic and market potential for the program by analyzing local industrial consumption by industry segment and time of day. This information will be used to better understand optimal system sizes based on the amount of own-use consumption (i.e. designs that maximize offsetting peak and intermediate periods of demand).

e. Present the result to the Huangpu DRB to gain their support on the next phase work.

2. Partner Assembly –

a. GIEC and Huangpu DRB prepare the list of industrial owners that have rooftop resource with both technical and likely market feasibility (ability to offset significant peak to intermediate grid demand).

b. GEI, Huangpu DRB and GIEC contact the major banks and foundations in Guangdong as well as the major solar PV developers.

c. Led by the local Solar Industry Association, solar PV developers prepare a standard financial package for projects within the program.

d. GIEC reviews the standard financial package with lenders to assure that it meets their needs. Also, GEI gathers information from each lender on their expected criteria for lending (e.g. project size, specific financial metrics to be achieved by the project).

e. After conducting some additional surveys of facility owners/operators, GIEC will conduct additional financial analyses for projects of different types. Projects may then be categorized to conform with expectations of different lenders (e.g. lender expectations for project size and specific financial metrics).

f. Huangpu DRB hosts a partner assembly workshop with all stakeholders to come up with a general agreement on the program and their roles.

g. Those factory owners that are interested in this program will start the next phase work with PV developers to develop their financial packages.

3. Program Marketing to Industry -

a. With support from the local Solar Energy Industry Association, solar PV project developers negotiate with factory owners for their agreement on the project.

b. GIEC provides technical assistance on the program if the factory owners don't have enough understanding of it.

4. Define and Aggregate Projects -

a. Solar PV project developers conduct field visit to the site to gather information for the system design.

b. Solar PV project developers will decide which building owners have the least risk and whether it is capable to build solar PV system.

c. Solar PV project developers finish project design and the proposal within the standard financial package.

d. Factory owners receive the proposal and evaluate it, GIEC will provide technical assistance if necessary. This will include aggregating the projects into marketable bins that can be presented to lenders in the next phase. GIEC will work with lenders to identify the key attributes of projects used for binning, such as system size, industry subsector, return on investment, etc.

5. Program Marketing to Lenders -

a. GIEC will assist project developers in submitting financial packages to lenders for the financing programs that are of interest to each lending institution (note: each program is a collection of individual projects). Note that all of the steps in this phase may be repeated by different combinations of project developer and lending institution.

b. Lending institution conducts financial evaluations of each program. This could include the financial status of the facility owner, if that information was not captured in the submittals of project developers.

c. Lending institution approves the loan for the program after evaluation.

d. Facility owners sign the contract with project developer.

e. Lending institution provides funds to the project developer to initiate the next phase of work.

6. Program Implementation -

a. Project developer orders equipment and commences the construction of the project(s)

b. After the system(s) are installed, HPSB does the work to interconnect the system(s) to the grid.

c. GEI and local government agencies monitor the project(s) via field check(s).

d. Facility owner(s) conduct an inspection for acceptance of the project(s) with assistance from project developers and GIEC.

e. After the acceptance inspection(s) is completed, the system(s) can put into operation.

f. HPSB will monitor the generation of the project(s) for payment of generation subsidies.

7. Program Scale-up -

a. GIEC conducts an industrial building rooftop area assessment of Guangzhou city or Guangdong province.

b. GIEC and GEI identify the area that is suitable for solar PV development.

c. GIEC presents the results to the Guangzhou DRC or Guangdong DRC to gain their support on the program scale-up.

d. Guangzhou DRC or Guangdong DRC selects areas that are prioritized for solar PV development.

e. GIEC works with local Power Supply Bureau and administrative entities of the selected area to identify the technical feasibility of adding program level quantities of solar generation to the grid.

f. Repeat Phases 2 through 6 in the selected areas.

Baseline Conditions: Existing or Planned Programs

For baseline conditions with respect to existing and planned industrial solar PV application in the Huangpu EDZ, please see the discussion under Technology Application and Design above. With regards to the current and expected centralized electricity supply mix for Guangdong Province, non-renewable generation is dominated by coal (also with a small amount of natural gas and fuel oil sources) and nuclear plants. The province also has some hydroelectric, pumped storage and wind generation. For the purposes of estimating GHG impacts, it is assumed that coal-based power production is the main source of power on the margin, meaning that it is the supply source that would be ramped down as a result of new generation coming on-line or a reduction of demand for grid-based power (both of these would result from the new distributed solar power generated from the Huangpu Program).

Metrics for Implementation Assessment

The methodologies, data sources and key metrics used to evaluate program implementation costs and benefits are documented below. The approach taken to financial analysis was to develop 3 model rooftop PV systems that are consistent with the team's findings regarding the availability of industrial building rooftops in the Huangpu EDZ. Detailed analysis was conducted and is documented below on the mid-size system. Summary financial results are provided for the small and large model PV systems.

BAU Electrical Energy Supply

1. Key Issues

Grid GHG emission offsets in this analysis are estimated using an emission rate of 850 kg CO_2/MWh (a typical rate for a conventional coal steam plant in Guangdong Province).[2] This rate is used to estimate the GHG benefits associated with all power produced by projects in the program. Its application assumes that conventional coal plants are the predominant generation source within the mix of sources that would be offset (turned down) as a result of more solar PV power production. In this analysis, the power generated by each project is used primarily on-site (own-use), with the remainder fed into the power grid.

2. Methodology: Local RE Supply

a. Local Resource Assessment

See the report footnoted below for more details on how the local resource assessment was conducted.[3] Based on rooftop measurements made in that analysis, a total of 320 MW of rooftop capacity above BAU levels of implementation was estimated. With input from the Guangdong Solar Energy Association (GSEA) on appropriate "packing factors" to convert available rooftop area to solar PV potential, the total technical potential above BAU was significantly upgraded to 680 MW. As described further below, additional analysis of GIS-based sampling of rooftop areas was conducted to establish 3 model system sizes for evaluation of impacts and costs. Summarized results from that assessment are provided in Table 2 below.

2 Value provided by GIEC.
3 http://www.climatestrategies.us/library/library/view/1222.

Although in a small number of cases, some very large rooftop areas were measured (e.g. >400,000 m^2), these were often collections of several large buildings rather than single buildings (see Figure 3 below). About 38% of rooftops fell into the first size bin up to 25,000 m^2. The mid-point of this size bin was selected to represent the small model system. About 25% of rooftops are in size bins greater than 75,000 m^2. The weighted average of these (167,000 m^2) was selected as the large model system. The median value of all measurements was selected to represent the mid-size model system (30,172 m^2). A scaling factor of 0.7 was applied to adjust total roof area to an area suitable for mounting PV panels (accounts for physical obstructions on rooftops, such as heating, ventilation and air conditioning equipment, etc.). Next, a packing factor[4] was applied to convert available roof area to MW of solar PV panels. For this analysis, a packing factor for fixed PV systems was selected (see Table 2; no single- or dual-axis tilt hardware are assumed).

Table 2. Model Industrial Rooftop Solar PV System Sizes and Installation Costs

Parameter	Small	Mid-Size	Large	Notes/Citations
Rooftop Area (m^2)	12,500	30,172	167,241	
Scaling Factor	0.7	0.7	0.7	Adjusts available rooftop area to account for physical space limitations for PV panels.
Rooftop Area Available for System	8,750	21,120	117,069	
Packing Factor (m^2/MW)	8,500	8,500	8,500	Fixed PV system selected. Value provided by the Guangdong Solar Energy Association.
System Size (MW)	1.5	3.5	20	
System Installed Costs (yuan)	¥5,823,952	¥13,013,148	¥67,131,703	These include grid inter-connection costs.
System Installed Costs (yuan/kW)	¥3,960	¥3,666	¥3,412	
Annual production (MWh)	2,121	5,119	28,377	

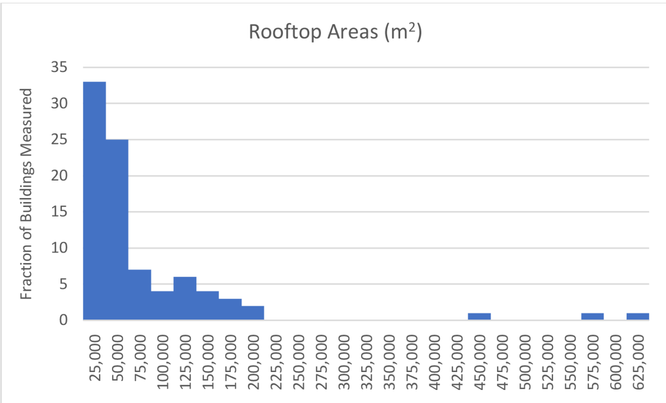
A discussion of initial installation costs for the model PV systems is provided in the next section.

a. Supply Technology Application Considerations:

i. Renewable power production: assuming the full technical potential of 680 MW is reached, total PV power production is estimated to be almost 778 GWh/yr. This estimate assumes a 16.8% capacity factor5 and DC:AC inversion efficiency of 98%.

ii. GHG emissions offset: based on the BAU carbon intensity stated above and assuming the full technical potential is reached, total GHG emissions offset will be about 851,000 tonnes of carbon dioxide equivalent (tCO2e/yr), assuming conventional coal-based generation is offset (850 kgCO_2e/MWh).

Figure 3 Rooftop Area Measurements used to Construct Model PV System Sizes



iii. Typical Industrial Rooftop PV system capital and operating costs:

iv. Generation characteristics: mid-size = 2.1 MW; size range = 0.9 – 11.9 MW.

v. Installation costs: mid-size = 8.11 million RMB for a median sized system; 3.53 million RMB for a small size system; and 43.76 million RMB for the large size system. Table 3 below provides details on the inputs used to calculate total installation costs, as well as other cost components.

4 8,500 m2/MW. Source: Guangdong Solar Energy Association (GSEA).
5 GSEA.

vi. Operation & maintenance (O&M) costs: variable O&M costs for solar PV projects are assumed to be zero. Fixed O&M is set at 133 RMB/kW-yr, meaning that the total cost by plant sizes are:[6] median size (mid-sized) plant = 286,615 RMB/yr; small plant = 118,769 RMB/yr; and large plant = 1,588,818 RMB/yr.

vii. Expected operating life = 25 years of operation at 80% guaranteed output performance (meaning that system output at the end of 25 years will be no less than 80% of the original system output). Typical system output degradation is expected to average 0.5%/yr.[7]

Table 3. Key Inputs for Evaluating Model PV System Operation and Costs

System Component Costs	Value	Units	Notes	Data Source
Equipment Costs				
Small System Inverter	0.25	yuan/Wdc	Table 4 component pricing for 200kW commercial system	Guangdong Solar Energy Association (GSEA)
Mid-Size Inverter	0.22	yuan/Wdc	Table 4 component pricing for 200kW commercial system	GSEA
Large Size Inverter	0.18	yuan/Wdc	Table 4 component pricing for 200kW commercial system	GSEA
Small System Module	1.85	yuan/Wdc	Crystalline silicon module	GSEA provided a range of 1.85 - 1.75 RMB/Wdc for small to large systems..
Mid-Size Module	1.80	yuan/Wdc	Crystalline silicon module	GSEA provided a range of 1.85 - 1.75 RMB/Wdc for small to large systems.
Large Size Module	1.75	yuan/Wdc	Crystalline silicon module	GSEA provided a range of 1.85 - 1.75 RMB/Wdc for small to large systems.
Small System: Racking	0.22	yuan/Wdc	Table 4 component pricing: high end of cost range	GSEA
Mid-Size System: Racking	0.22	yuan/Wdc	Table 4 component pricing: mid-point of cost range	GSEA
Large System: Racking	0.22	yuan/Wdc	Table 4 component pricing: low end of cost range	GSEA
Equipment Overhead Costs and Profit				
Small System	9.0%	% total Eqpt.	Costs and fees of equipment provider overhead, inventory, shipping, handling. Plus 2% installer/developer profit	NREL, 2016: https://www.nrel.gov/docs/fy16osti/66532.pdf
Mid-Size System	9.0%	% total Eqpt.	Costs and fees of equipment provider overhead, inventory, shipping, handling. Plus 2% installer/developer profit	NREL, 2016: https://www.nrel.gov/docs/fy16osti/66532.pdf
Large System	9.0%	% total Eqpt.	Costs and fees of equipment provider overhead, inventory, shipping, handling. Plus 2% installer/developer profit	NREL, 2016: https://www.nrel.gov/docs/fy16osti/66532.pdf
Small System	0.21	yuan/Wdc	Calculated	
Mid-Size System	0.20	yuan/Wdc	Calculated	
Large System	0.19	yuan/Wdc	Calculated	

6 $20/kW-yr value from National Renewable Energy Laboratory (NREL, 2016), "Distributed Generation Renewable Energy Estimate of Costs", updated February 2016, and available as http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.

7 Personal communication with Longi Solar, China.

System Component Costs	Value	Units	Notes	Data Source
Sales Tax				
Small System	1.7%	% total Eqpt.	added-value tax	https://wenku.baidu.com/view/23dca2b76394dd88d0d233d4b14e852458fb393a.html
Mid-Size System	1.7%	% total Eqpt.	added-value tax	https://wenku.baidu.com/view/23dca2b76394dd88d0d233d4b14e852458fb393a.html
Large System	1.7%	% total Eqpt.	added-value tax	https://wenku.baidu.com/view/23dca2b76394dd88d0d233d4b14e852458fb393a.html
Small System	0.039	yuan/Wdc	Calculated	
Mid-Size System	0.038	yuan/Wdc	Calculated	
Large System	0.037	yuan/Wdc	Calculated	
Installation				
Small System	0.50	yuan/Wdc		Source: GSEA
Mid-Size System	0.40	yuan/Wdc		Source: GSEA
Large System	0.35	yuan/Wdc		Source: GSEA
Permitting, Testing, Interconnection, Commissioning				
Small System	0.80	yuan/Wdc	Also includes system design costs, which were not included in the equipment costs above.	Source: GSEA
Mid-Size System	0.70	yuan/Wdc		
Large System	0.60	yuan/Wdc		
Contingency Cost				
Small System	3.0%	% total Eqpt.	% of engineering, procurement, and construction costs	http://www.sohu.com/a/224213146_703050
Mid-Size System	3.0%	% total Eqpt.	% of engineering, procurement, and construction costs	http://www.sohu.com/a/224213146_703050
Large System	3.0%	% total Eqpt.	% of engineering, procurement, and construction costs	http://www.sohu.com/a/224213146_703050
Small System	0.09	yuan/Wdc	Calculated	
Mid-Size System	0.09	yuan/Wdc	Calculated	
Large System	0.08	yuan/Wdc	Calculated	
Total System Costs				
Small System	3.96	yuan/Wdc	Calculated	
Mid-Size System	3.67	yuan/Wdc	Calculated	
Large System	3.41	yuan/Wdc	Calculated	
Other Inputs				
DC:AC Inversion Losses				
Small System	2%	%	Assumed	
Mid-Size System	2%	%	Assumed	
Large System	2%	%	Assumed	

3. Key Metrics

a. Total Technical Potential Initial Investment Costs: 2.54 billion RMB for system installations. These break down as follows by size class: small systems, 258 MW and 1.02 billion RMB; median size systems, 242 MW and 888 million RMB; and for large systems, 180 MW and 614 million RMB. Note that these estimates assume that the full technical potential of 680 MW can be attained. The financial analysis conducted below suggests that the market potential for the program could be less than that, and will likely be tied to the capacity that can be installed which will closely meet the peak and intermediate rate demands of industrial facilities in the program area (i.e. offsetting the most expensive grid power through own-use of power generated).

b. Total Technical Potential Operations & Maintenance Costs: 90.4 million RMB/yr.

c. Note: no assessment has been conducted to compare industrial rooftop PV systems costs and performance characteristics with and without battery storage; nor to compare the incremental costs and performance of single- and dual-axis tracking systems with fixed systems. These are significant issues, since the value of power used for own-use is at present much more valuable in Guangdong Province than is power sold to the grid (and thus the increase in capacity factor achieved via storage or tracking could well be worth the expense).

d. Levelized cost of electricity (LCOE) – based on installed costs and financing assumptions for the median size system, an LCOE estimate of a nominal 0.42 RMB/kWh produced was estimated. See the Financial Analysis section below for more details on these costs. This compares to a benchmark of 0.37 RMB/kWh for coal-based generation.[8] There are several formulas needed to convert the various units into the ¥/MWh units used to express levelized costs. For background, these are briefly described below.

Initial Investment Costs (IIC) : These costs are annualized to ¥/MWh units for each year of expected plant operation as per the formula below:

Annualized IIC = IIC * FCF * 1000 / (8760 * C_f)

where:
IIC = initial investment costs. These include the capital costs of land and equipment, as well as any other initial costs for planning, engineering and construction (¥/kW)
C_f = capacity factor (%)
8760 = hours per year
FCF = fixed charge factor
1000 = conversion from ¥/kW to ¥/MW

Fixed O&M (FOM) : These costs can be estimated for each year of system operation in ¥/MWh units as per the formula below:

Annualized fixed O&M cost = FOM * 1000 / (8760 * C_f)
where:
FOM = fixed O&M (¥/kW-yr; note that these are subject to annual escalation at or above the rate of inflation)
C_f = capacity factor (%)
8760 = hours per year
1000 = conversion from ¥/kW to ¥/MW

Variable O&M (VOM) : These costs should already be provided in units of ¥/MWh, so no conversion is needed.

Discounted Costs: All of the annual costs estimated above are then discounted as follows:

Discounted Annual Costs = [PV_{GEN} * DR * $(1+DR)^t$] / [(1 + DR)t – 1]

where:
PV_{GEN} = present value of the sum of all generation costs
= annualized IIC + FOM + VOM + FC (¥/MWh in each year of the plant's lifetime)
DR = discount rate

The values in the stream of discounted annualized costs are then levelized across the lifetime of the plant:

LCOE = ∑ Discounted Annual Costs/PL

where:
LCOE = levelized cost of electricity (¥/MWh)
PL = lifetime of the plant (years)

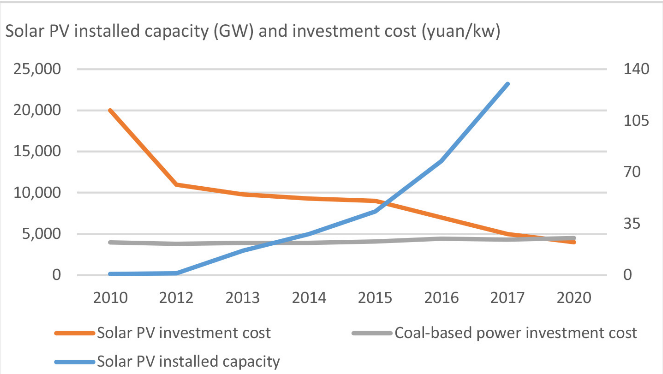
e. Grid sales price for solar PV: below is a summary of national grid sales prices for solar PV. Guangdong Province is in Sector III. More reductions are expected, until the price reaches the same level of conventional power sources (e.g. conventional coal-based generation). Because of these trends and expectations, a very conservative price to be paid by the grid operator for solar power provided to the grid was adopted for this program analysis. The value was set at ¥0.37/kWh which is the current estimated cost for coal-based power generation in Guangdong Province.

8 Note that this comparison ignores that a distributed power source, like an industrial PV system in Huangpu, would also offset the additional conventional generation lost during transmission and distribution (likely in the 7-10% range in Guangdong Province), since power is consumed at or near the point of generation. In net societal impacts analysis, these additional benefits should be included. However, here, the analysis is being done from the system owner's perspective, and that owner needs to evaluate the cost of power generation for addition to the grid against conventional generation sources.

Unit: ￥/kwh	Before 2015	2016	2017	2018	After June 2018
Sector I	0.90	0.80	0.65	0.55	0.50
Sector II	0.95	0.88	0.75	0.65	0.60
Sector III	1.0	0.98	0.85	0.75	0.70
Average power generation cost	0.68	0.65	0.60	0.57	0.53

The chart below provides a summary of the sharp reduction in solar PV installation costs and rise in installed capacity during recent years. The chart also provides the installation costs for coal as a comparison. This indicates that the capacity installation costs for the two technologies are expected to be similar within the next couple of years. Since these comparisons do not include fuel and other running costs for coal, one would expect that the LCOE for solar PV should fall below that of coal by 2020.

The team assumed a PV power sales price to the grid of 0.37 RMB/kWh for all power sales to the grid. This sales value was kept fixed during future years as an additional conservative assumption. However, to the extent that power generation from conventional sources increases in the future, then the priced paid to PV system owners could also increase. Note that another conservative assumption is for the initial system costs. These costs are continuing to decline and are expected to in the future; however, the team's assumed costs are based on recent literature values and input from GSEA.



Another option for system configuration and operation that could be considered by project owners is direct sale of power to another local user. For example, the system could be sized to offset all of the project owner's peak and flat rate power and also that of a nearby facility. The power could be sold to the other local user at a discount to the retail pricing from grid-based power and still provide a profit to the project owner. This option was not analyzed as part of any of the model systems analyzed.

To further account for the declining prices paid for solar PV, the team **did not apply** a 2018 national production subsidy of 0.32 RMB/kWh or the 2020 provincial production subsidy of 0.16 RMB/kWh. Also, no national production subsidies were applied in subsequent years. Separately, a 0.10 RMB/kWh city-level production subsidy **was applied** for the first 6 years of the project.

4. Program/Project Impact: Dependent on the interests of government reviewers or other stakeholders, the Team could also develop estimates for other key program metrics in addition to the standard assessment results presented in the next section, which concentrate on electricity and GHG impacts and the financial feasibility of the program, for example:

- Contribution toward city-level or provincial target(s): e.g. new MW of RE capacity.
- Program Achievement: at full technical potential, the team estimates a total of 172 small systems, 69 mid-size systems, and 9 large systems (for a total of 250 systems). As indicated above, the market potential for the program is expected to be smaller, either in number of systems or in the size of the systems installed (in some cases, smaller systems may offer better financial performance, since they would match up better with the facility's daily pattern of power consumption).
- Fossil Fuel Savings: will decrease 1.23 million tons coal annually once full technical potential has been reached.
- Direct Job Creation: Using 133 ¥/kW-yr for fixed O&M costs, up to 90.4 million RMB/yr of operations and maintenance costs would result in the local economy. This represents a potentially significant number of local jobs to serve those ongoing O&M needs. A recent estimate from the International Renewable Energy Agency (IRENA)[9] suggests that one 50MW solar power plant creates more person-days of employment (229,055) than a similarly sized fossil fuel plant.
- Foreign Investment: while this may be expected in developing countries, foreign investment is not anticipated to play a major role in this program.

9 https://twitter.com/irena/status/974807528486985728.

Results of Program Assessment at Technical Potential

This section provides a summary of the quantified impacts and costs for the Program at its technical potential which is assumed to be reached by 2025. The section begins with a set of summary tables that present key results. A discussion of these results is then presented.

Table 4. RE Energy and Emissions Assessment Results

2025 PV Generation (GWh)	2019 - 2035 PV Generation (GWh)	2025 Annual Coal Offset (TJ)	2025 GHG Reduction (tCO_2e)	2019 – 2035 GHG Reduction ($Tg\ CO_2e$)
1,001	~15,500	~10,900	~851,000	~13.1
Notes: these estimates are based on meeting the 680 MW technical potential for the program.				

Table 5. RE Technology Market Assessment

Capacity of RE Resource (MW)	2025 Annual Net Generation (GWh)	Median PV System Size (MW)	Expected Range of PV System Size (MW)	Potential Number of PV System Installations
TBD	TBD	2.1	0.9 – 11.9	250
Notes: The first two values related to market assessment could be determined with information on local industrial power demand; including some breakdown of power use during peak, flat and base rate periods. This and other relevant program information is expected to be gathered in the next phases of program implementation described in the Implementation Model at the beginning of this document.				

Table 6. Model Project and Program Financial Assessment Summary

Project Size	Initial Investment Costs (RMB)	NPV of Implementation Costs (million 2018 RMB)	Discounted Payback (on owner equity) (Years)	Internal Rate of Return (%)	Risk-Adjusted Return on Investment (%)
Small (0.9 MW)	¥3,531,704	¥0.68	5.7	1.6	6
Median (2.1 MW)	¥8,115,882	¥14	4.8	26.2	60
Large (11.9 MW)	¥43,762,906	¥49	4.4	27.7	62
Huangpu Program Costs					
320 MW	¥1.55 Billion	¥2,458	Not applicable	Not applicable	Not applicable
Notes: key assumptions include an own-use of power generated value of 67%, and a capacity factor of 16.8% applied to all 3 systems. Small system assumes 50% initial owner equity. Mid- and large systems assume 30% owner equity.					

A. Energy and Emissions Results

- **Direct Energy and Emissions Impacts**

Table 6 provides a summary of the expected energy and emissions impacts for the entire program, if implemented at full technical potential. If all 680 MW of technical potential were implemented, then annual power generation in 2025 would be about 1,001 GWh. This assumes a PV capacity factor of 0.168. If all power generated by the program offsets conventional coal-based generation, there would be a reduction in coal usage of about 1.23 million tons in 2025. This level of coal-based power offset would reduce 2025 GHG emissions by about 851,000 tons of carbon dioxide equivalent (tCO2e). Cumulatively, through 2035, the Program would reduce GHG emissions by about 13.1 teragrams (Tg or million tonnes) CO2e. As stated above, these program-level results assume implementation at the full technical potential estimated. The market potential will be smaller (possibly significantly) and is limited by the amount of power generated by these new projects that can be used to offset high-cost grid-based consumption at each facility.

- **Key Uncertainties**

Among the key uncertainties in the analysis of implementation costs are the value of any sales of power to the grid and the value of any grid-based consumption that is offset as a result of direct use by the industrial facility of the power that it generates (referred to as "own-use"). All of the team's assumptions are provided along with the discounted cash flow (DCF) analysis in the Financial Analysis subsection below.

For sales to the grid, the province is expected to continue its adjustments for renewable power downwards towards parity with conventional sources (e.g. coal) at 0.37 RMB/kWh (note that this is the value before any production subsidies, which are also being phased out). The team made a conservative assumption that this value would not increase in real terms, although it is certainly possible that future sales prices for solar PV projects would rise along with the cost of conventional generation. National production subsidies of 0.33 RMB/kWh for 2019, 0.16 RMB/kWh for 2020 were excluded, and no national subsidies were assumed for any future years. Municipal production subsidies (0.15 RMB/kWh) were included for the first six years of operation. A municipal investment credit of 0.20 RMB/W was included (this maxes out at 2 million RMB for any single project).

The assumed price of avoided power consumption from the grid via own-use of solar PV power is 0.80 RMB/kWh, which is the average of the peak (1.0 RMB/kWh) and flat rate periods (0.60 RMB/kWh). This corresponds to most of the hours during which solar PV projects would be generating power. That rate is assumed to increase at 0.25%/yr which is the annual historic rate of real growth in industrial retail rates. It's clear from these inputs that the best return for industrial projects will be those that can use a significant portion of the power generated for own-use.

The emission reduction benefits assume that it is only conventional coal-based generation that is on the margin which means that it is the technology that will be ramped down as a result of a combination of lower grid demand (associated with projects where at least some of the power is being consumed by the industrial facility) and new supply of RE added to the grid (associated with projects that are grid-tied and supplying new RE). To the extent that other generation sources are on the margin (and would be backed down), then the estimated emission reductions would be lower (other generation resources, including natural gas, have lower emission levels than coal).

- **Feasibility Issues**

  - The research team did not assess feasibility of grid integration for any specific project associated with the Huangpu Program.

  - The research team did not evaluate whether partial or full implementation of the program would produce any grid reliability issues, such as possible over generation during certain portions of the day.

  - A key consideration for any project is whether or not the industrial operator also owns the building in which they operate. For situations where the owner is a different party, then some change to the financial strategies will be needed to adequately compensate this landlord. For example, rather than a contract being made between the industrial operator and the PV project developer, the contact would more likely be between the building owner and the PV project developer. Some form of rental payment back to the building owner would likely be required to make this strategy work. The team has not yet investigated how large such rental payments would need to be.

  - During the next phases of implementation, the team will convene workshops involving Huangpu industry operators, PV developers, and local government. Assessments will be conducted during these phases of implementation to determine whether there are any structural issues with certain rooftops that would prevent the application of solar PV. The current estimates of technical potential do not include a consideration of rooftop space that should be excluded from the program for this reason.

B. PV System-Level Assessment

This section summarizes the results of the systems-level assessments conducted for each of the model PV system sizes introduced above. The initial background work conducted by the team to assess the technical potential of solar PV generation in the Huangpu EDZ was documented in a previous study as a case example.[10]

- Local Industrial Rooftop PV Potential

For the Huangpu EDZ, planning data were available for the northern section of the EDZ (referred to as the "New Knowledge City") on industrial rooftop areas that were either already built or included in the development plan. For the already built-out southern portion of the EDZ, an assessment was done within a geographic information system (GIS) using satellite imagery to estimate the amount of industrial rooftop available (see the study cited below for more background). The scaling and packing factors cited in Table 2 above were then applied to provide an overall estimate of technical potential (680 MW) for the Huangpu Program.

For a mid-size (2.1 MW) project, the estimated LCOE is ¥0.42/kWh, which is lower than the estimated LCOE for coal-based power in Guangdong Province (¥0.37/kWh).[11] This estimate assumes 67% own-use of electricity generated. At 50% or lower values for own-use of electricity generated, the return on investment (ROI) falls below 100%, which has been set the initial threshold for interest by industrial business owners. As further detailed in the next section, some remaining government incentives and the price of avoided grid consumption at 0.80 RMB/kWh contribute to provide for very positive financial performance. Note: this assessment has not looked into the financial viability of battery or other storage technologies, nor the use of single- or dual-axis tracking systems for increasing the capacity factors of the systems installed). As well, options for project owners to sell some of their generation to other local users at a profit will increase the number and size of projects that can operate profitably. Notably, the values cited above for the mid-size system do not include any payments needed to compensate a building owner for rooftop rental (i.e. it assumes that that industrial operator owns the building in which it operates).

Work is ongoing to assess the amount of local industrial power consumption that could be offset with PV-based generation. This information will be gathered in the next phases of program implementation. Specifically, this requires gathering data on local industrial power consumption during the peak and flat rate periods. Projects that align PV capacity with offsetting power use during these time periods could be financially-attractive to industry.

- Jurisdictional (Provincial-scale) RE Market Potential (Program Scale-Up)

Work on estimating the RE market potential for industrial solar PV projects throughout Guangdong Province will be conducted in the next phases of program implementation. This work requires information on the consumption of electricity by industry locally within Huangpu during peak, intermediate, and base demand periods of the day. That information could be used to more accurately assess the size of systems that produce the best financial returns (e.g. facilities that have high intermediate and peak load consumption). The team expects that systems will be sized in order to maximize returns, which means that in some cases, the entire rooftop would not be utilized.

C. Project/Program Financial Assessment

Financial risk, return, and impact. Three relevant categories of financial risk are market risk, policy risk and credit risk. Market risk refers to the risk by the project owner and lender due to changing conditions in the marketplace that could impact the viability of the RE technology being deployed (for example, advances in technology that make the financed project obsolete). A possible example for industrial solar PV could be a reduction in electricity demand due to process changes or energy efficiency. Policy risk considers changes in government policies that have a significant impact on a project's financial viability (again affecting both project owner and lender). For solar PV projects, this could include changes in government production subsidies or sales prices. Credit risk is the risk that lenders incur by extending credit to borrowers. Lenders take on a risk that borrowers could default on payments. The financial assessment documented here is meant to address all forms of project risk; however, some aspects of credit risk would have to be analyzed based on the specific business operating cash flows of a Huangpu Program applicant (e.g. future debt obligations that could affect an applicant's ability to meet the debt service incurred by taking part in the solar PV program).

Results presented below address the typical Industrial Rooftop PV projects associated with the Program. The table at the front of this section lists the relevant metrics for assessing program/project financing, including financial risk. Relevant metrics for option financing should include at a minimum: simple payback , discounted payback and net present value (NPV) of the discounted cash flows from the project. Other financial metrics that may be of interest to lending institutions are the internal rate of return (IRR) and return on investment (ROI) or risk-adjusted ROI.

A discounted cash flow (DCF) analysis is central to a financial analysis for any project. Table 7 below presents a DCF analysis for the mid-size model PV system (3.5 MW) for the Huangpu Program. The phases of the project are: Installation and First Year of Operation; Continued Operation during the Finance Period; Continued

10 Renewable Energy Implementation Toolkit: Development and Testing in South China, prepared by the Center for Climate Strategies, Guangzhou Institute of Energy Conversion, and the Global Environmental Institute, November 2017; http://www.climatestrategies.us/library/library/view/1222.

11 https://www.sohu.com/a/224213146_703050.

Operation at Guaranteed Power Production; and Continued Operation Beyond Warranty Period. The first half of the table shows the total investment costs (total installation) and the annual streams of both costs (columns with red headers) and revenues for the project owner (green columns).

Key inputs to the DCF analysis are provided in Tables 8 and 9 below. Total investment costs for the system are ¥13,013,148. The initial equity investment for the example project is ¥1,750,771 which is 30% of total investment costs (the minimum amount expected by lenders in south China). The debt service cost stream is calculated based on the financing assumptions provided in Tables 8 and 9 below. Fixed operations and maintenance (O&M) costs address routine maintenance of each system and cleaning of panels. No variable O&M costs are expected. Taxes address those paid for all income sources derived from the project (investment credit, power sales revenue, and the provincial and city-level production subsidies). The income streams include a city-level investment credit, power sales to the grid operator, provincial and city-level production subsidies, and cost savings from own-use of power generated by the project (avoided purchases from the grid).

Table 7. Discounted Cash Flow Analysis, Mid-Size Rooftop Solar PV Project

Project Phase	Year	Total Installation Costs	Owner's Down-payment	Debt Service	Rooftop Rental Fees	Fixed O&M	Taxes	Government Investment Credit	Net Generation	Power Sales Revenue	Production Subsidy	Avoided Grid Electricity Cost
		¥	¥	¥	¥	¥	¥	¥	kWh	¥	¥	¥
Installation and First Year of Operation	2019	¥-8,115,882	¥-2,434,765	¥-853,541	¥0	¥-287,494	¥-121,581	¥431,025	3,108,221	¥379,514	¥0	¥1,666,007
Continued Operation during Finance Period	2020	¥0	¥0	¥-853,541	¥0	¥-299,108	¥-57,601		3,083,356	¥384,007	¥0	¥1,689,946
	2021	¥0	¥0	¥-853,541	¥0	¥-311,192	¥-58,283		3,058,689	¥388,554	¥0	¥1,714,230
	2022	¥0	¥0	¥-853,541	¥0	¥-323,765	¥-58,973		3,034,219	¥393,154	¥0	¥1,738,863
	2023	¥0	¥0	¥-853,541	¥0	¥-336,845	¥-59,671		3,009,945	¥397,809	¥0	¥1,763,850
	2024	¥0	¥0	¥-853,541	¥0	¥-350,453	¥-60,378		2,985,866	¥402,519	¥0	¥1,789,196
	2025	¥0	¥0	¥-853,541	¥0	¥-364,611	¥-61,093		2,961,979	¥407,285	¥0	¥1,814,906
	2026	¥0	¥0	¥-853,541	¥0	¥-379,342	¥-61,816		2,938,283	¥412,107	¥0	¥1,840,985
	2027	¥0	¥0	¥-853,541	¥0	¥-394,667	¥-62,548		2,914,777	¥416,987	¥0	¥1,867,439
	2028	¥0	¥0	¥-853,541	¥0	¥-410,612	¥-63,289		2,891,459	¥421,924	¥0	¥1,894,274
Continued Operation at Guaranteed Power Production	2029	¥0	¥0	¥0	¥0	¥-427,200	¥-64,038		2,868,327	¥426,920	¥0	¥1,921,494
	2030	¥0	¥0	¥0	¥0	¥-444,459	¥-64,796		2,845,380	¥431,974	¥0	¥1,949,105
	2031	¥0	¥0	¥0	¥0	¥-462,416	¥-65,563		2,822,617	¥437,089	¥0	¥1,977,113
	2032	¥0	¥0	¥0	¥0	¥-481,097	¥-66,340		2,800,036	¥442,264	¥0	¥2,005,523
	2033	¥0	¥0	¥0	¥0	¥-500,533	¥-67,125		2,777,636	¥447,500	¥0	¥2,034,342
	2034	¥0	¥0	¥0	¥0	¥-520,755	¥-67,920		2,755,415	¥452,799	¥0	¥2,063,574
	2035	¥0	¥0	¥0	¥0	¥-541,794	¥-68,724		2,733,372	¥458,160	¥0	¥2,093,227
	2036	¥0	¥0	¥0	¥0	¥-563,682	¥-69,538		2,711,505	¥463,585	¥0	¥2,123,306
	2037	¥0	¥0	¥0	¥0	¥-586,455	¥-70,361		2,689,813	¥469,073	¥0	¥2,153,817
	2038	¥0	¥0	¥0	¥0	¥-610,147	¥-71,194		2,668,294	¥474,627	¥0	¥2,184,766
	2039	¥0	¥0	¥0	¥0	¥-634,797	¥-72,037		2,646,948	¥480,247	¥0	¥2,216,161
	2040	¥0	¥0	¥0	¥0	¥-660,443	¥-72,890		2,625,772	¥485,933	¥0	¥2,248,006
	2041	¥0	¥0	¥0	¥0	¥-687,125	¥-73,753		2,604,766	¥491,686	¥0	¥2,280,309
	2042	¥0	¥0	¥0	¥0	¥-714,885	¥-74,626		2,583,928	¥497,508	¥0	¥2,313,076
	2043	¥0	¥0	¥0	¥0	¥-743,766	¥-75,510		2,563,256	¥503,398	¥0	¥2,346,314

Project Phase	Year	Total Installation Costs	Owner's Down-payment	Debt Service	Rooftop Rental Fees	Fixed O&M	Taxes	Government Investment Credit	Net Generation	Power Sales Revenue	Production Subsidy	Avoided Grid Electricity Cost
		¥	¥	¥	¥	¥	¥	¥	kWh	¥	¥	¥
Continued Operation Beyond Warranty Period	2044	¥0	¥0	¥0	¥0	¥-773,815	¥-76,404		2,542,750	¥509,359	¥0	¥2,380,030
	2045	¥0	¥0	¥0	¥0	¥-805,077	¥-77,308		2,522,408	¥515,389	¥0	¥2,414,230
	2046	¥0	¥0	¥0	¥0	¥-837,602	¥-78,224		2,502,229	¥521,492	¥0	¥2,448,921
	2047	¥0	¥0	¥0	¥0	¥-871,441	¥-79,150		2,482,211	¥527,666	¥0	¥2,484,111
	2048	¥0	¥0	¥0	¥0	¥-906,647	¥-80,087		2,462,354	¥533,914	¥0	¥2,519,807
	2049	¥0	¥0	¥0	¥0	¥-943,276	¥-81,035		2,442,655	¥540,235	¥0	¥2,556,015
	2050	¥0	¥0	¥0	¥0	¥-981,384	¥-81,995		2,423,114	¥546,632	¥0	¥2,592,744

Project Phase	Period	Year	Owner's Net Cash Flow	Owner's Discounted NCF	Depreciated Value of System	Discounted Costs	Discounted Benefits	Cumulative Cash Flows	Cumulative Discounted Cash Flows
			¥	¥2018	¥	¥2018	¥2018	¥	¥2018
Installation and First Year of Operation	1	2019	¥-1,220,834	¥-1,220,834	¥8,115,882	¥-3,697,380	¥2,476,545	¥-1,220,834	¥-1,220,834
Continued Operation during Finance Period	2	2020	¥863,704	¥806,123	¥7,791,246	¥-1,129,567	¥1,935,690	¥-357,131	¥-414,711
	3	2021	¥879,768	¥766,376	¥7,466,611	¥-1,065,383	¥1,831,759	¥522,638	¥351,665
	4	2022	¥895,739	¥728,269	¥7,141,976	¥-1,005,140	¥1,733,409	¥1,418,377	¥1,079,934
	5	2023	¥911,603	¥691,756	¥6,817,341	¥-948,586	¥1,640,342	¥2,329,979	¥1,771,690
	6	2024	¥927,343	¥656,787	¥6,492,705	¥-895,486	¥1,552,273	¥3,257,323	¥2,428,477
	7	2025	¥942,946	¥623,315	¥6,168,070	¥-845,618	¥1,468,933	¥4,200,269	¥3,051,791
	8	2026	¥958,394	¥591,291	¥5,843,435	¥-798,778	¥1,390,069	¥5,158,663	¥3,643,083
	9	2027	¥973,670	¥560,669	¥5,518,800	¥-754,772	¥1,315,441	¥6,132,333	¥4,203,751
	10	2028	¥988,757	¥531,399	¥5,194,164	¥-713,422	¥1,244,820	¥7,121,090	¥4,735,150
Continued Operation at Guaranteed Power Production	11	2029	¥1,857,175	¥931,581	¥4,869,529	¥-246,411	¥1,177,992	¥8,978,265	¥5,666,731
	12	2030	¥1,871,824	¥876,334	¥4,544,894	¥-238,419	¥1,114,752	¥10,850,089	¥6,543,065
	13	2031	¥1,886,223	¥824,203	¥4,220,258	¥-230,705	¥1,054,909	¥12,736,311	¥7,367,268
	14	2032	¥1,900,350	¥775,018	¥3,895,623	¥-223,261	¥998,278	¥14,636,661	¥8,142,286
	15	2033	¥1,914,183	¥728,616	¥3,570,988	¥-216,074	¥944,689	¥16,550,845	¥8,870,901
	16	2034	¥1,927,698	¥684,842	¥3,246,353	¥-209,135	¥893,978	¥18,478,543	¥9,555,744
	17	2035	¥1,940,869	¥643,554	¥2,921,717	¥-202,435	¥845,989	¥20,419,413	¥10,199,297
	18	2036	¥1,953,671	¥604,612	¥2,597,082	¥-195,965	¥800,577	¥22,373,083	¥10,803,909
	19	2037	¥1,966,075	¥567,887	¥2,272,447	¥-189,717	¥757,604	¥24,339,158	¥11,371,796
	20	2038	¥1,978,052	¥533,257	¥1,947,812	¥-183,681	¥716,938	¥26,317,210	¥11,905,053
	21	2039	¥1,989,573	¥500,605	¥1,623,176	¥-177,850	¥678,455	¥28,306,783	¥12,405,658
	22	2040	¥2,000,606	¥469,822	¥1,298,541	¥-172,216	¥642,039	¥30,307,388	¥12,875,481
	23	2041	¥2,011,117	¥440,805	¥973,906	¥-166,772	¥607,577	¥32,318,505	¥13,316,286
	24	2042	¥2,021,073	¥413,455	¥649,271	¥-161,512	¥574,966	¥34,339,578	¥13,729,740
	25	2043	¥2,030,436	¥387,679	¥324,635	¥-156,427	¥544,106	¥36,370,014	¥14,117,419

Project Phase	Period	Year	Owner's Net Cash Flow	Owner's Discounted NCF	Depreciated Value of System	Discounted Costs	Discounted Benefits	Cumulative Cash Flows	Cumulative Discounted Cash Flows
			¥	¥2018	¥	¥2018	¥2018	¥	¥2018
Continued Operation Beyond Warranty Period	26	2044	¥2,039,170	¥363,390	¥0	¥-151,513	¥514,903	¥38,409,184	¥14,480,809
	27	2045	¥2,047,234	¥340,505	¥0	¥-146,762	¥487,267	¥40,456,418	¥14,821,314
	28	2046	¥2,054,587	¥318,946	¥0	¥-142,169	¥461,116	¥42,511,005	¥15,140,260
	29	2047	¥2,061,187	¥298,639	¥0	¥-137,728	¥436,368	¥44,572,192	¥15,438,900
	30	2048	¥2,066,986	¥279,514	¥0	¥-133,434	¥412,948	¥46,639,178	¥15,718,414
	31	2049	¥2,071,940	¥261,505	¥0	¥-129,281	¥390,786	¥48,711,118	¥15,979,919
	32	2050	¥2,075,997	¥244,550	¥0	¥-125,265	¥369,814	¥50,787,116	¥16,224,469

Table 8. Key Project Inputs and Assumptions: Mid-Size Rooftop PV System

Parameter	Value	Units	Notes and References
First Year of Analysis Period	2019	yr	
Plant Lifetime	25	years	Assumed; based on warranty period.
Plant Gross Capacity	2155	kW	Gross capacity
Plant Net Capacity	2112	kW	Adjusted for inversion efficiency.
Project Installed Cost	3.7	¥/W	See Model PV Systems and System Cost details presented above.
Plant Interconnection	0	¥	Included in total project costs.
Total Project Costs	8,115,882	¥	Assumed; includes equipment, engineering, permitting and all other costs related to initial construction and start-up.
Value of Grants	0	¥	None are applicable to this program.
Plant Capacity Factor	0.168	unitless	Provided by the Guangdong Solar Energy Association.
Rooftop Rental	0	¥/MW-yr	Not applicable for this analysis; these may be needed for a business model that includes some form of rental payment to the building owner (i.e. when the facility operator does not own the building).
Rooftop Rental Escalation Rate	0.0%	%	Not applicable for this analysis.
Net Generation - Year 1	3,108,221	kWh/yr	Calculated; includes adjustment for the assumed project development duration (e.g. number of months remaining in the first year when the system begins operation).
PV System Output Degradation Rate	0.5%	%/yr	Provided by reviewers from Longi Solar.
Variable O&M	0.00	¥/kWh	Solar PV variable O&M costs are assumed to be zero.

Parameter	Value	Units	Notes and References
Power production for own use	67%	%	Assumed mid-point of the range based on this citation:http://www.pvplus.com.cn/service/pvNewsDetail.aspx?id=700ea088d-81c469985f51b2eba8cc6d0.
Fixed O&M	133	¥/kW-yr	Assumed; $20/kW-yr value from National Renewable Energy Laboratory (NREL, 2016), "Distributed Generation Renewable Energy Estimate of Costs", updated February 2016, and available as http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.
O&M Escalation Rate	2.0%	%/yr	Assumed; however, for this analysis, these costs are escalated only at the rate of inflation.
LCOE benchmark	0.37	¥/kWh	LCOE value for coal-based power production in Guangdong Province; source:

Table 9. Key Cost and Financing Inputs and Assumptions

Parameter	Value	Units	Notes and References
Plant Owner Equity (initial down-payment)	30%	%	Assumed at the low end of the equity range required by lenders (30%-70%).
Plant Owner Equity	2,434,765	¥	Calculated
Total Financed	5,681,117	¥	Total project costs minus value of grants and owner equity
Power sales price	0.37	¥/kWh	Assumed based on the current price paid for conventional power (mainly coal).
Value of production for own-use	0.80	¥/kWh	Power Consumption pricing for Industry is assumed to increase at the annual historic rate of retail electricity pricing. It is the average of the peak (1 RMB/kWh) and flat rate periods (0.6 RMB/kWh).
Annual escalation: value of production	0.25%	%/yr	Based on historical rates of electricity retail rates for industry; used to estimate future value of own-use electricity
2019 Provincial Government Production Subsidy (Feed-in Tariff)	0.33	¥/kWh	Removed from the DCF analysis. This production subsidy is being phased out and is expected to be 0 by 2021.
2020 Provincial Government Production Subsidy (Feed-in Tariff)	0.16	¥/kWh	Removed from the DCF analysis. This production subsidy is being phased out and is expected to be 0 by 2021.
City-level Production Subsidy (Feed-in Tariff)	0.15	¥/kWh	Applied for 15 years to the amount of power supplied to the grid; based on current generation subsidy rate.
City-level Investment Credit	0.20	¥/W	Maximum 2 million RMB for a single project.
Carbon Offset Credit	0	¥/tCO2e	Not applicable for this analysis.
Rate of Inflation	2.0%	%	Assumed; range is assumed to be 0.5-3.25% based on China consumer price index data from the past 5 years (https://tradingeconomics.com/china/inflation-cpi).
Development Period Duration	0.5	year	Assumed; this value means that the project would be up and running at the mid-point of the first year.
Corporate Income Tax: Period 1	8.5%	%	Applied for the first 3 years of the project; (Income+Subsidy)/(1+rate) × Rate
Corporate Income Tax: Period 2	12.5%	%	Applied to years 4 through 6.
Corporate Income Tax: Period 3	25.0%	%	Applied to years 7 and beyond.
RMB to USD	6.67	¥/USD	Assumed.

Parameter	Value	Units	Notes and References
Debt ratio (%)	70%	%	Assumed.
Discount Rate (nominal)	5.0%	per year	Assumed; in financial analysis an appropriate metric to use is the Weighted Average Cost of Capital (WACC). WACC is different for each company and is dependent on its cost of equity, cost of debt, market value of company’s debt and equity, and corporate tax rate. Assumed range for this analysis is 3.0-10%
Interest Rate	8.2%	per year	Estimated by GIEC. Assumed range is 4.35% to 12.0%.
Period of Loan	10	years	Estimated by GIEC. Assumed range is 8 to 15 years.
Capital Recovery Factor (CRF)	0.15	unitless	Derived from the interest rate and loan period.
Salvage Value	-	¥	Not applied for this analysis.

The second half of Table 7 provides the annual calculation of net cash flows both in nominal and discounted values (in 2018 RMB). These streams of costs were used in calculating the key financial metrics shown in Table 10 below. Key financial metrics that exceed the team's selected target are shown in green, while those that fail to meet their target are shown in red. Over the first 25 years of the project (warranty period for power production), the net income to the owner will be ¥8.83 million (the target here is any value sufficiently above zero). The IRR value of 26.2% is greater than the minimum target, which is a value sufficiently greater than the cost of capital (8.2%). The calculated ROI of 60% is greater than the team's presumed threshold of 100%, which is based on values that the team has seen in the literature describing the level of returns sought by some types of business owners (and assumed to be applicable to industrial operators in Guangdong Province).

The value shown in Table 10 for "Investment Cut-Off Period" provides the team's selection of a value for the expected payback period (PBP) by industrial facility owners (5 years). In reality, some businesses have even shorter expectations for payback period, possibly as short as 2 years. This is a key issue for exploration with industry stakeholders in the Huangpu EDZ. The calculated values for simple PBP and discounted PBP are 4.3 and 4.8 years, respectively. The latter of these adjusts for risk in the future value of money. Both of these are shown in green, since they slightly are both within the selected target for the investment cut-off period. The benefit to cost (BC) ratio is shown in green, since it exceeds the target of 1.0 (benefits exceed costs). For this analysis, the benefits are more than twice the value of costs. Finally, the NPV of implementation costs provides the total costs for the project which include initial owner equity, financing, and O&M.

Table 10. Financial Analysis Key Metrics

Analysis Case: **- Mid-Size Industrial Rooftop Solar PV System (3.5 MW); Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years** **- Huangpu Economic Development Zone, Guangzhou, PRC** **- 67% Own use of power; no storage. Remainder sold to grid operator.** **- Owner equity of 30%, plus financing**		
Total Initial Investment (¥)	**¥8,115,882**	Industrial Rooftop Solar PV System; including equipment, installation and grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**¥8,835,067**	2019-2043; net income to owner
Internal Rate of Return (IRR) %	**26.2%**	2019-2043; should be greater than the Cost of Capital
Minimum Acceptable Rate of Return (MARR) %	**8.2%**	Cost of Capital
Return on Investment - ROI (%)	**60%**	2019-2043; some businesses may require 100% or higher ROI.
Investment Cut-Off Period (years)	**5.0**	Assumed industry target for payback period
Payback Period - PBP (years)	**4.3**	Simple payback on equity
Discounted PBP (years)	**4.8**	Risk-adjusted payback on equity
Benefit to Cost (BC) Ratio	**1.60**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.43**	¥/kWh, Undiscounted; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥14,676,376**	2019-2043; equity, debt service, O&M

In addition to the key financial metrics, the calculated levelized cost of electricity (LCOE) value is lower than conventional sources, such as coal, in Guangdong Province, with current values of about ¥0.37/kWh. This suggests that there may be financial room in at least some of these projects to consider a slightly different financial strategy than those presented at the beginning of this document, whereby a rooftop rental payment is made to building owners. This would be done in cases where an industrial facility operator does not own the building. The team has not yet analyzed this alternative strategy, including the level of rooftop rental payments that could be supported while still providing attractive financial metrics for project developers and industry operators.

Similar summaries for the small (0.9 MW) and large (11.9 MW) model system sizes are provided in the Annex to this document. Overall, the financial metrics look good across all system sizes. For example, risk-adjusted payback is still under 4-6 years for all project sizes. For large systems (11.9 MW), the economies of scale provide the best metrics with an internal rate of return at 27.7%, ROI at 62%, and discounted PBP of 4.4 years. In addition, the LCOE of power generated drops to 0.41 RMB/kWh (as compared to the target of 0.37 RMB/kWh).

A sensitivity analysis was carried out on the calculation of discounted NCF for mid-size systems. This assessment involved identifying the key variables expected to drive uncertainty in its calculation. Below, these variables are identified along with their assumed distributions:

• **Plant capacity factor** (fraction of rated output that the system achieves each year): the team's point estimate provided by the Guangdong Solar Energy Association was 0.168. This compares to a reported range in the literature for southeast China is from 0.127 to 0.145.[122] This variable was assigned a triangular distribution with a mode of and upper bound of 0.168 and a lower bound of 0.127.

• **Fraction of power production for own-use**: the amount of generated power that the facility consumes to offset its use of power from the grid. This variable was assigned a triangular distribution with a mode of 67%, a lower bound of 10% and an upper bound of 90%.

• **Fixed O&M costs**: these costs were assumed to vary by up to +/-30%. This variable was assigned a uniform distribution with a lower bound of 93 ¥/kW-yr and an upper bound of 173 ¥/kW-yr.

• **City production subsidy**: this value was assigned a triangular distribution with a mode of 0.10 ¥/kWh, a lower bound of 0.0 ¥/kWh, and an upper bound of 0.10 ¥/kWh.

• **Rate of inflation**: this variable was assigned a triangular distribution with a mode of 2.00%, a lower bound of 0.50% and an upper bound of 3.25%.

• **Plant owner equity**: the down-payment of total project costs by the plant owner. This variable was assigned a uniform distribution with a lower bound of 30% (the minimum expected by Chinese lenders) and an assumed upper bound of 70%.

• **Nominal discount rate**: this variable was assigned a triangular distribution with a mode of 5.0%, a lower bound of 3.0%, and an upper bound of 10%.

• **Interest rate (cost of capital)**: this variable was assigned a triangular distribution with a mode of 8.2%, a lower bound of 4.4% and an upper bound of 12%.

• **Loan period**: this variable was assigned a triangular distribution with a mode of 10 years, a lower bound of 8 years, and an upper bound of 15 years.

• **Power sales price**: this variable is assumed to have a value equal to the current price paid for power from conventional sources (mostly coal) in Guangdong Province. That price is ¥0.37/kWh. A triangular distribution was assigned with a mode of ¥0.37/kWh, a lower bound of ¥0.37/kWh, and an upper bound of ¥0.48/kWh. The upper bound assumes that the current price paid for power supplied to the grid could rise by up to 30%, based on the potential for future coal price increases (resulting from a combination of lower domestic production and higher import prices).

• **Value of own-use production**: this variable was assigned a triangular distribution with a mode of ¥0.80/kWh, a lower bound of ¥0.60/kWh, and an upper bound of ¥1.00/kWh. The lower bound is the current flat rate charged to industry, while the upper bound is the peak rate.

• **Equipment costs**: Equipment costs were assigned a uniform distribution with a mode of ¥2.48/Wdc for mid-size systems (provided by GSEA). [13]A lower bound representing a 20% reduction in equipment costs (based on a continued decline in the cost of panels and other equipment) and an upper bound of 10% higher costs than values obtained from the literature.

• **Equipment installation costs**: System installation costs were assigned a triangular distribution with a mode of ¥0.40/Wdc, a lower bound of the same value, and an upper bound representing 30% installation contingencies (¥0.52/Wdc).

Figures 4 and 5 below provide summaries of a Monte Carlo simulation of NCF for the mid-size model PV system (recall from Table 10 above, using point estimates for all variables produced an NCF of ¥8.83 million). Summary stats for the 1,000 trials used to construct the distribution in Figure 4 are: mean = ¥16.9 million; median = ¥16.4 million; std. deviation = ¥6.2 million; maximum = ¥39.4 million; minimum = ¥1.3 million; range = ¥38.1 million. Figure 5 provides a cumulative probability density chart from the Monte Carlo simulation of discounted NCF. As shown, it indicates that there is less than a 10% chance that the discounted NCF will fall below 9.6 million 2018RMB. The variables contributing to the down-side risks from this uncertainty analysis are identified and further explored in the sensitivity analysis below. Down-side risk variables are those that drive the result lower, as they themselves rise; upside variables are those that drive the result higher, as they themselves rise.

Note that these simulations also indicate a potential for higher estimates for NCF of almost 10% (values in Figure 5 above the point estimate of ¥8.83 million initially estimated. However, more likely than not, both lender and project owner would be more focused on downside risks to NCF. For example, significant reductions in cash flow could present risks to the lender for loan repayment. Although, this may be less likely with industrial borrowers than with other sectors (residential or small commercial borrowers).

Next, a sensitivity analysis was carried out to explore which factors were driving uncertainty in the NCF estimates, and their attribution to upside and downside risk to NCF. As with the Monte Carlo simulation above, the sensitivity analysis was carried out using an MS Excel add-on called Argo. [14] The sensitivity analysis is calculated using one factor (variable) at a time (OFAT) to determine its potential for driving the median value of NCF higher or lower. Table 11 provides a summary of the inputs and outputs of the analysis. Figures 6 and 7 provide graphical presentations of the outputs as a spider chart and tornado chart, respectively.

12 Guangdong average for commercial PV reported by He and Kammen, 2016: https://rael.berkeley.edu/wp-content/uploads/2015/08/He-and-Kammen-Solar-Resource-for-China-2015.pdf; range is 0.127-0.145 based on the range reported for southeast Chinese provinces for commercial PV.

13 For comparison, total equipment costs for the small model systems were estimated to be ¥2.57/Wdc and for large model systems to be ¥2.38/Wdc.

14 http://boozallen.github.io/argo/. Argo is a free add-on to MS Excel.

Figure 4. Monte Carlo Simulation: NCF Probability Density

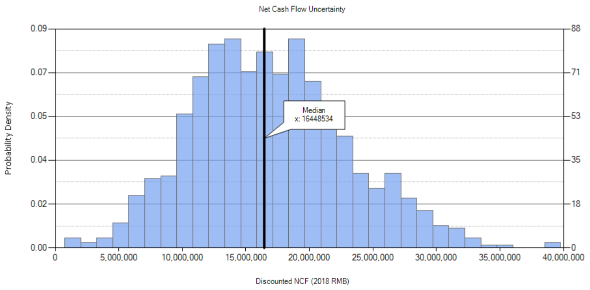
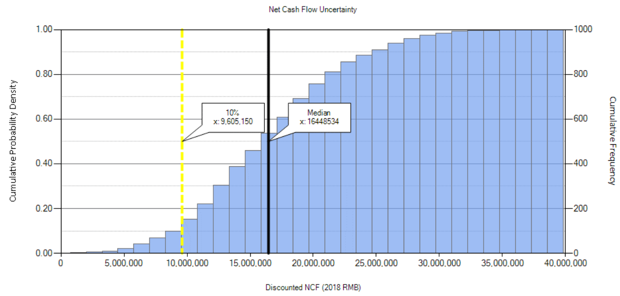


Figure 5. Monte Carlo Simulation: Cumulative Discounted NCF



The output values in Table 11 and Figure 6 show that the fraction of own-use power variable (fraction of power generated to satisfy the facility's demand for flat and peak rate periods) is the variable to which estimated discounted NCF is most sensitive (it is the line with the greatest slope in Figure 6). In Figure 6, variables with positive slopes have greater upside potential than downside. Those with a negative slope have greater downside than upside potential. Other important variables with greater upside include own-use production value (cost of retail electricity offset by the system) and the plant capacity factor (note in Table 11 that this value is only being varied by less than one percent). Variables that drive greater downside than upside risk include the discount rate, fixed O&M costs, and mid-size system equipment costs (with the discount rate being the most important).

Table 11. OFAT Sensitivity Analysis Inputs and Outputs

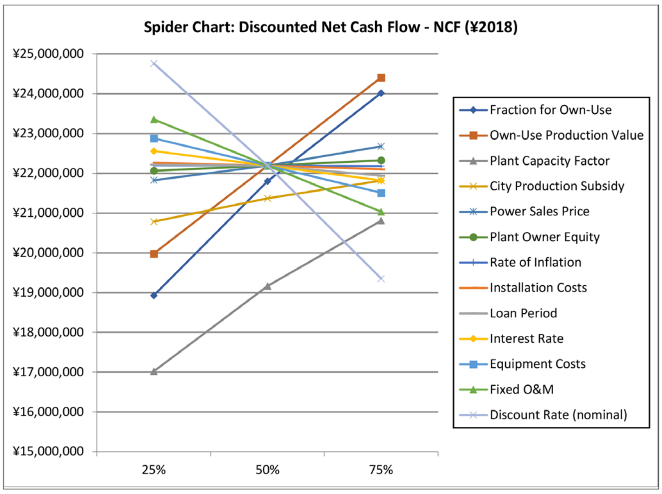
	Spider Chart: Discounted Net Cash Flow - NCF (¥2018)						Tornado Chart: Discounted Net Cash Flow - NCF (¥2018)		
	Input			Output					
Variable	25%	50%	75%	25%	50%	75%	Downside	Upside	Range
Fraction for Own-Use	0.44	0.58	0.69	¥18,926,470	¥21,800,077	¥24,019,789	¥18,926,470	¥24,019,789	¥5,093,319
Own-Use Production Value	¥0.74	¥0.80	¥0.86	¥19,979,868	¥22,194,407	¥24,408,946	¥19,979,868	¥24,408,946	¥4,429,078
Plant Capacity Factor	0.15	0.16	0.16	¥17,020,701	¥19,163,720	¥20,808,117	¥17,020,701	¥20,808,117	¥3,787,415
City Production Subsidy	¥0.08	¥0.11	¥0.13	¥20,785,022	¥21,368,809	¥21,816,764	¥20,785,022	¥21,816,764	¥1,031,741
Power Sales Price	¥0.38	¥0.40	¥0.43	¥21,824,458	¥22,194,407	¥22,676,534	¥21,824,458	¥22,676,534	¥852,076
Plant Owner Equity	0.40	0.50	0.60	¥22,063,083	¥22,194,407	¥22,325,731	¥22,063,083	¥22,325,731	¥262,648
Rate of Inflation	¥0.02	¥0.02	¥0.02	¥22,202,281	¥22,194,486	¥22,180,366	¥22,202,281	¥22,180,366	-¥21,915
Installation Costs	¥0.42	¥0.44	¥0.46	¥22,264,653	¥22,194,407	¥22,102,860	¥22,264,653	¥22,102,860	-¥161,793
Loan Period	9.9	10.8	12.0	¥22,214,792	¥22,194,407	¥21,940,160	¥22,214,792	¥21,940,160	-¥274,632
Interest Rate	7.06%	8.18%	9.30%	¥22,559,546	¥22,194,408	¥21,820,762	¥22,559,546	¥21,820,762	-¥738,784
Equipment Costs	¥2.2	¥2.4	¥2.5	¥22,879,460	¥22,194,407	¥21,509,354	¥22,879,460	¥21,509,354	-¥1,370,106
Fixed O&M	¥113	¥133	¥153	¥23,354,594	¥22,194,407	¥21,034,220	¥23,354,594	¥21,034,220	-¥2,320,374
Discount Rate (nominal)	4.9%	5.8%	7.0%	¥24,762,578	¥22,194,407	¥19,353,585	¥24,762,578	¥19,353,585	-¥5,408,994

Key take-aways from the uncertainty and sensitivity analysis conducted above are as follows:

• Due to the restriction in production subsides going forward, projects that can utilize a large percentage of power generated for their own needs **(fraction of own-use)** will have much better overall economics, as well as lower NCF sensitivity. Projects that can use two-thirds of the power produced can produce good financial metrics (see Table 11), although the payback period may be longer than desired by some industry owners. At roughly 50% or lower own-use levels, project financial metrics are not attractive. Therefore, while a facility may have room for a 1.4 MW system on its roof, that system should be sized to best meet its own needs for offsetting purchases from the grid. Alternative system ownership models could also be explored. For example, an industrial facility could also directly supply other nearby enterprises or households with power that it produces rather than selling to the grid. This issue on fraction of own-use becomes more important with decreasing system size. In the Annex to this document, summary financial metrics are shown for the small and large size model systems. The differences between input variables are 50% initial owner equity for small systems versus 30% for mid- to large size systems and the equipment costs for small, mid-, and large systems.

• Timing of own-use electricity off-sets is also important, since this affects the rate at which electricity savings from avoided grid use would be calculated (own-use production **value)**. Projects where most of the electricity use is during peak rate periods will achieve the best financial metrics.

Figure 6. OFAT NCF Sensitivity Spider Chart.



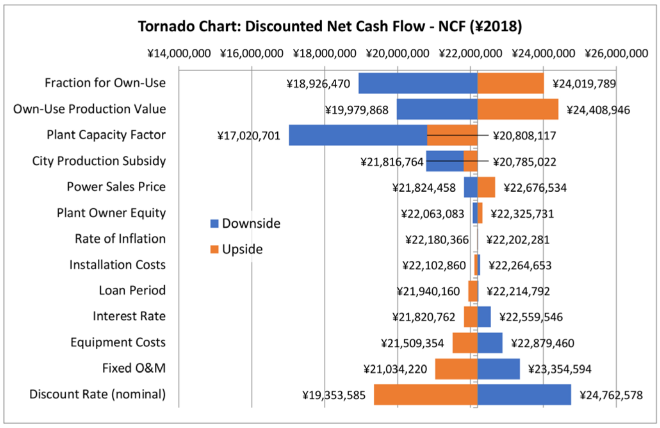
Values on the X axis indicate the value of the variable being applied in the sensitivity analysis. For example, 50% is the median value of each variable, 25% is the 25th percentile. Note that since the sensitivity analysis was carried out using the median values of each variable, rather than the mean, the prediction of NCF is slightly lower than the point estimate provided in Table 10 above.

• Proper system siting is a critical issue: even a 1% difference in **capacity factor** can drive significant changes to net cash flow (see Figure 7). Guangdong Province has sufficient solar resources to produce financially-attractive projects, but any obstructions to sunlight (e.g. neighboring buildings or vegetation) could severely impact project economics. While not investigated in this analysis, the additional costs of tracking systems (single or dual axis) should be explored to maximize the system's capacity factor.

• The assumed **nominal discount rate** applied to the analysis is also a key variable in the assessment of net cash flow. In financial analysis, an appropriate metric to use is the Weighted Average Cost of Capital (WACC). WACC is different for each company and is dependent on its cost of equity, cost of debt, the market value of a company's debt and equity, and the corporate tax rate. The assumed range for this analysis was 3.0-10%/yr, and the mode was set at 5.0%/yr. Companies that have low perceived investment risks (that is, strong financials, and low debt) would have a lower WACC, and therefore lower NCF sensitivity to this variable.

• **Fixed O&M costs** are also a variable that drives a fair amount of risk to NCF. Figure 7 shows that as fixed O&M rises to the upside, then NCF is driven down by about ¥1.0 million). So, any project (or program of multiple projects) that can reduce these costs (and still assure operational performance) will improve the financial metrics estimated for the model system. O&M issues and approach should receive sufficient attention in any lending application. This would include selection of low to no maintenance alternatives throughout the system when available, use of network connected inverters for remote testing, software configuration and/or update, remote resets, and other approaches.[15]

Figure 7. OFAT Sensitivity Tornado Chart.



For "upside" variables at the top of the chart, an increase in their value drives NCF higher; greater values for "downside" variables toward the bottom of the chart drive NCF lower. Key downside risk variables are fraction for own-use, own-use production value, discount rate, and fixed O&M costs.

D. Trading and Other Policies

This section identifies linkages to the provincial cap and trade programs, international carbon programs, or other policies.

• Applicability and value of any relevant carbon offsets, renewable energy credits, or other attributes derived from the Huangpu Program: there is no direct linkage of emission offset credits available to industrial facilities taking part in the Program. However, due to the coverage of fossil fuel generators by the provincial program cap and trade program, projects implemented as a result of the Program

15 Best Practices in Photovoltaic Systems Operations and Maintenance, National Renewable Energy Lab, US DOE, December 2016. https://www.nrel.gov/docs/fy17osti/67553.pdf.

should have a slight cost advantage for power sales tied indirectly to the carbon price. Currently, it is not clear whether the current power sales (¥0.37/kWh) price offered to fossil fuel generators incorporates any cost for GHG emissions or other environmental externalities (e.g. safe storage of coal ash; health, crop and other environmental impacts of air pollutant emissions). These issues are still under investigation by the project team.

Program-Level Financial Assessment

The model system analyses described above indicate that good financial performance is possible at all system sizes, presuming that a large fraction of peak rate power use can be offset (at least 50%). It is possible that lower levels of own-use power could still provide acceptable performance for some facilities (e.g. those willing to accept longer payback periods). During the next phase of Program implementation as described at the beginning of this document, the Team will begin to engage industry contacts in the Huangpu EDZ, project developers, and interested funders. With more details on local power demand, and the expectations for financial returns, the true market potential of the Program will be better understood.

An example program-level financial assessment follows to show what the financial metrics might look like to one or more financiers. While there are many different ways in which the program could be implemented, below are a set of program design assumptions applied for the purposes of demonstration:

- **Program Size:** 340 MW of mid- to large size industrial rooftop PV systems. This represents half of the technical potential estimated for the Huangpu EDZ. Large size systems represent 180 MW, and the remaining 160 MW are all mid-size systems. All systems are configured to produce a minimum of 50% of their power for offsetting a 50:50 mixture of peak and flat rate grid demand.

- **Financial Strategy:** this largely follows Financial Strategy 1 from Figure 2 at the beginning of this document, but with a slight change to address revenue share for grid demand savings. A solar developer will receive a loan to help finance system installations. The solar developer will sell 50% of power generated to the grid; and will sell the other 50% of power back to the industrial facility at a rate that is 30% lower than grid-based peak power. The solar developer will repay the loan using the revenues obtained from system installs.

Figure 8 shows the discounted cash flows for the overall program. Table 12 provides a summary of financial metrics using a discount rate of 8.2%. Financial metrics for the overall Program look good with the possible exception of IRR at 7.5%. Tables 9 and 10 provide the same metrics but with discount rates of 13.2% and 20%, respectively. Program financial metrics still seem reasonable at a discount rate of 13.2% (Table 9) with the exception of IRR and discounted PBP. However, at a discount rate of 20%, discounted cash flow has turned negative along with the rest of the key metrics.

Figure 8. Discounted Cash Flow for the Example Solar PV Program

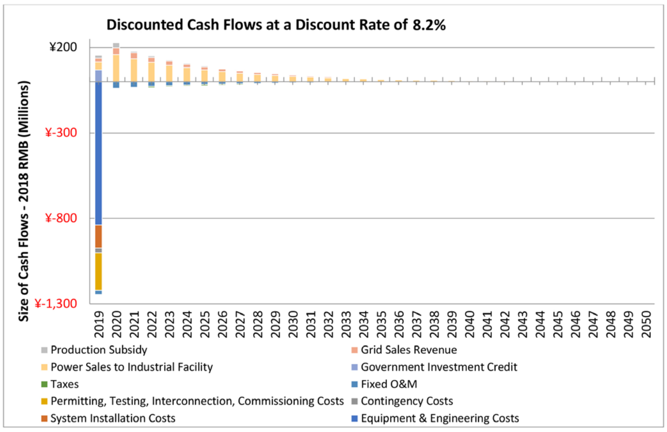


Table 8. Financial Metrics for the Example Program with a Discount Rate of 8.2%

Analysis Case: **- Combination of Mid- to Large-Size Industrial Rooftop Solar PV Systems (2.1 – 11.9 MW); 340 MW total; Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years** **- Huangpu Economic Development Zone, Guangzhou, PRC** **- 67% of power produced sold back to facility to offset peak demand; no storage.**		
Total Initial Investment (¥)	**¥1,222,943,962**	340 MW Industrial Rooftop Solar PV Program; including grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**¥748,635,398**	2019-2043; net income for the program
Internal Rate of Return (IRR) %	**7.5%**	2019-2043; should be greater than the discount rate
Minimum Acceptable Rate of Return (MARR) %	**8.2%**	Discount rate
Return on Investment - ROI (%)	**40%**	2019-2043; Expectations threshold set at 9.0% based on investor expectations for Asia out of Singapore and Hong Kong: https://www.cnbc.com/2016/09/29/ordinary-investors-expect-an-85-percent-return.html.
Investment Cut-Off Period (years)	**10.0**	Investor target for payback period
Payback Period - PBP (years)	**6.3**	Simple payback on program costs
Discounted PBP (years)	**9.2**	Risk-adjusted payback on program costs
Benefit to Cost (BC) Ratio	**1.40**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.42**	¥/kWh, Undiscounted; excludes subsidies; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥1,856,856,286**	2019-2043; investments and O&M

Table 9. Financial Metrics for the Example Program with a Discount Rate of 13.2%

Analysis Case: **- Combination of Mid- to Large-Size Industrial Rooftop Solar PV Systems (3.5 - 20 MW); 340 MW total; Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years** **- Huangpu Economic Development Zone, Guangzhou, PRC** **- 67% of power produced sold back to facility to offset peak demand; no storage.**		
Total Initial Investment (¥)	**¥1,222,943,962**	340 MW Industrial Rooftop Solar PV Program; including grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**¥210,630,758**	2019-2043; net income for the program
Internal Rate of Return (IRR) %	**2.8%**	2019-2043; should be greater than the discount rate
Minimum Acceptable Rate of Return (MARR) %	**13.2%**	Discount rate
Return on Investment - ROI (%)	**13%**	2019-2043; Expectations threshold set at 9.0% based on investor expectations for Asia out of Singapore and Hong Kong: https://www.cnbc.com/2016/09/29/ordinary-investors-expect-an-85-percent-return.html.
Investment Cut-Off Period (years)	**10.0**	Investor target for payback period
Payback Period - PBP (years)	**6.3**	Simple payback on program costs
Discounted PBP (years)	**13.1**	Risk-adjusted payback on program costs
Benefit to Cost (BC) Ratio	**1.13**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.42**	¥/kWh, Undiscounted; excludes subsidies; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥1,666,090,047**	2019-2043; investments and O&M

Table 10. Financial Metrics for the Example Program with a Discount Rate of 20%

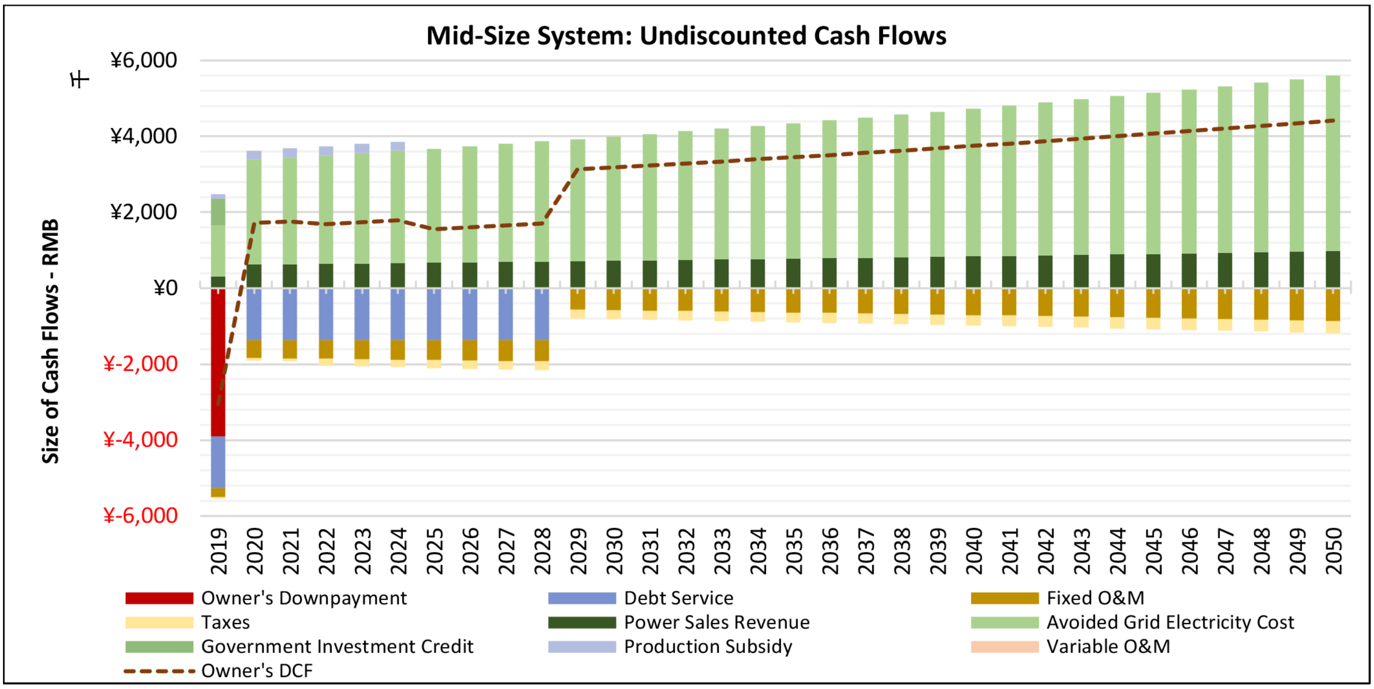
Analysis Case: **- Combination of Mid- to Large-Size Industrial Rooftop Solar PV Systems (3.5 - 20 MW); 340 MW total; Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years** **- Huangpu Economic Development Zone, Guangzhou, PRC** **- 67% of power produced sold back to facility to offset peak demand; no storage.**		
Total Initial Investment (¥)	**¥1,222,943,962**	340 MW Industrial Rooftop Solar PV Program; including grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**-¥177,172,623**	2019-2043; net income for the program
Internal Rate of Return (IRR) %	**-3.1%**	2019-2043; should be greater than the discount rate
Minimum Acceptable Rate of Return (MARR) %	**20.0%**	Discount rate
Return on Investment - ROI (%)	**-12%**	2019-2043; Expectations threshold set at 9.0% based on investor expectations for Asia out of Singapore and Hong Kong: https://www.cnbc.com/2016/09/29/ordinary-investors-expect-an-85-percent-return.html.
Investment Cut-Off Period (years)	**10.0**	Investor target for payback period
Payback Period - PBP (years)	**6.3**	Simple payback on program costs
Discounted PBP (years)	**349.1**	Risk-adjusted payback on program costs
Benefit to Cost (BC) Ratio	**0.88**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.42**	¥/kWh, Undiscounted; excludes subsidies; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥1,531,313,141**	2019-2043; investments and O&M

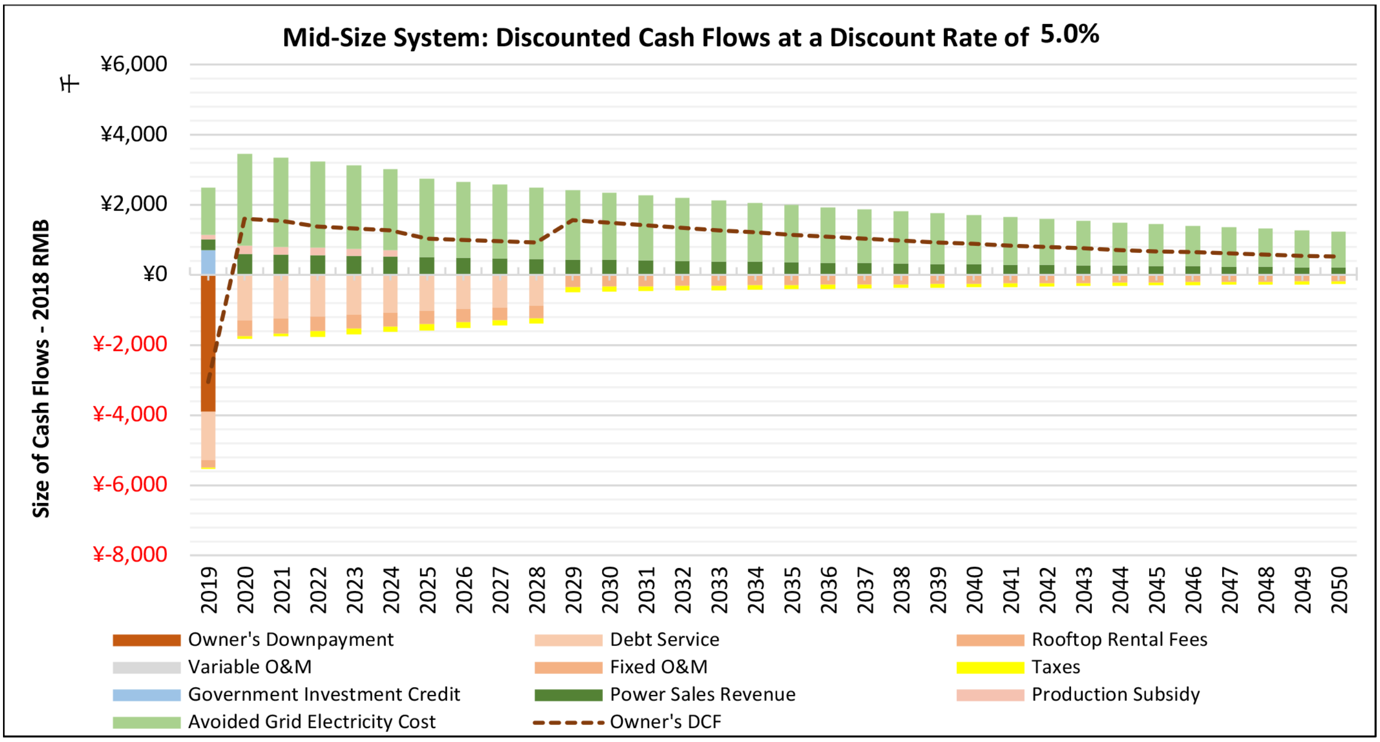
Status of Approvals

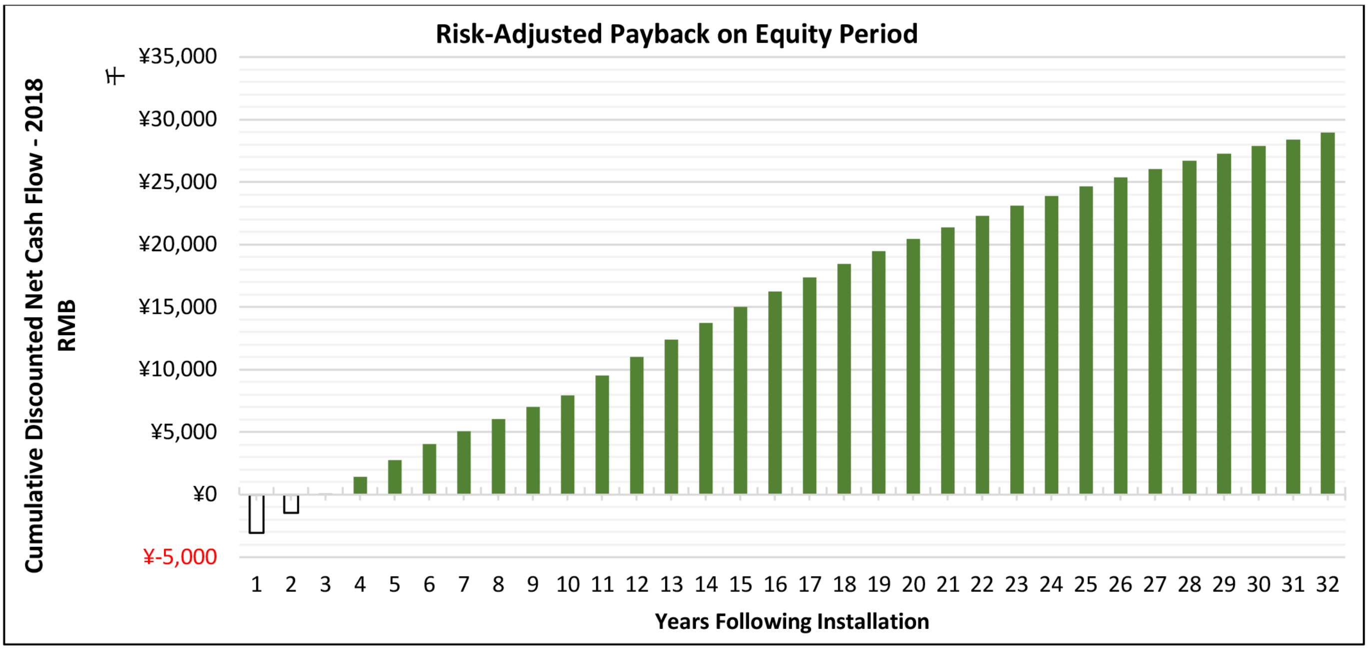
[The material in this section will reflect the status of the Program as it moves through the phases of Implementation Plan and the approvals of each phase and step by the partners in the Program.]

Annex A

Below are some additional summary charts from the financial analysis documented above for the mid-size industrial PV system.







Below are the summary financial metrics for the small and large size solar PV systems, respectively.

Analysis Case:
- Small Size Industrial Rooftop Solar PV System (0.9 MW); Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years
- Huangpu Economic Development Zone, Guangzhou, PRC
- 67% Own use of power; no storage; remainder sold to grid operator; no rooftop rental payments
- 30% of total system costs by owner, remainder financed

Total Initial Investment (¥)	**¥3,531,704**	Industrial Rooftop Solar PV; including equipment, installation and grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**¥3,476,386**	2019-2043; net income to owner
Internal Rate of Return (IRR) %	**22.2%**	2019-2043; should be greater than the Cost of Capital
Minimum Acceptable Rate of Return (MARR) %	**8.2%**	Cost of Capital
Return on Investment - ROI (%)	**55%**	2019-2043; some businesses might require 100% or higher ROI.
Investment Cut-Off Period (years)	**5.0**	Assumed industry target for payback period
Payback Period - PBP (years)	**4.9**	Simple payback on equity
Discounted PBP (years)	**5.7**	Risk-adjusted payback on equity
Benefit to Cost (BC) Ratio	**1.55**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.44**	¥/kWh, Undiscounted; excludes subsidies and investment credits; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥6,264,284**	2019-2043; equity, debt service, O&M

Analysis Case: **- Large Size Industrial Rooftop Solar PV System (20 MW); Fixed Array of Crystalline Silicon Modules; 80% Warranty over 25 years** **- Huangpu Economic Development Zone, Guangzhou, PRC** **- 67% Own use of power; no storage; remainder sold to grid operator; no rooftop rental payments** **- 30% of total system costs by owner, remainder financed**		
Total Initial Investment (¥)	**¥43,762,906**	Industrial Rooftop Solar PV; including equipment, installation and grid connection costs.
Discounted Net Cash Flow - NCF (¥2018)	**¥49,970,539**	2019-2043; net income to owner
Internal Rate of Return (IRR) %	**27.7%**	2019-2043; should be greater than the Cost of Capital
Minimum Acceptable Rate of Return (MARR) %	**8.2%**	Cost of Capital
Return on Investment - ROI (%)	**62%**	2019-2043; some businesses might require 100% or higher ROI.
Investment Cut-Off Period (years)	**5.0**	Assumed industry target for payback period
Payback Period - PBP (years)	**4.1**	Simple payback on equity
Discounted PBP (years)	**4.5**	Risk-adjusted payback on equity
Benefit to Cost (BC) Ratio	**1.62**	2019-2043 discounted
Levelized Cost of Electricity - LCOE (¥/kWh)	**¥0.42**	¥/kWh, Undiscounted; excludes subsidies and investment credits; benchmark is conventional coal at ¥0.37/kWh.
NPV of Implementation Costs (¥2018)	**¥79,963,739**	2019-2043; equity, debt service, O&M

References and End Notes

1 Typically reported in units of $/kW, these costs include the total costs of construction, including land purchase, land development, permitting, interconnections, equipment, materials and all other components. Construction financing costs are also included.

2 This factor is calculated based on assumptions regarding the plant lifetime, the effective interest rate or discount rate used to amortize capital costs, and various other factors specific to the power industry. Expressed as a decimal, typical fixed charge factors are typically between 0.10 and 0.20, meaning that the annual cost of ownership of a power generation technology is typically between 10 and 20 percent of the capital cost. Fixed charge factors decrease with longer plant lifetimes, and increase with higher discount or interest rates.

3 Typically reported in units of $/kW-yr, these costs are for those that occur on an annual basis regardless of how much the plant operates. They typically include staffing, overhead, regulatory filings, and miscellaneous direct costs.

4 Typically reported in units of $/MWh, these costs are for those that occur on an annual basis based on how much the plant operates. They typically include costs associated with maintenance and overhauls, including repairs for forced outages, consumables such as chemicals for pollution control equipment or boiler maintenance, water use, and other environmental compliance costs.

5 See the following web resource for more details on metrics cited here and footnoted below: http://searchcrm.techtarget.com/answer/Metrics-ROI-IRR-NPV-payback-discounted-payback.

6 Simple payback is calculated by comparing the cumulative cash investment in the program/projects and comparing it against the cumulative benefits, typically year by year in a timeline. Most programs/projects have a significant up-front investment, and then over time, this investment is recouped post deployment with benefits. Eventually, the benefits catch up to and exceed the initial and on-going investments required. The duration from initial investment to the point where the cumulative benefits exceed the costs is the payback period.

7 In Discounted payback, the costs and benefits of the project are discounted as they occur over time to take into account the lost opportunity of investing the cash elsewhere (usually set equal to a company's cost of capital) and further by a relative measure of the projects risk (the cost of capital + a risk generated discount rate). For projects with long payback periods, discounted payback periods are more accurate at determining the real payback. As with regular payback period, making investment decisions based purely on payback period can orient the team towards quick payback projects without regard to the ultimate benefit quantity – which is best measured using NPV.

8 NPV is a formula that tallies all of the net benefits of a project (benefits – costs), adjusting all results into today's currency terms. This is different than just tallying up all of the net benefits of a project over a ten year period without discounting as the cumulative benefits without discounting overstate the overall project value, especially when the project has many of the investment costs up-front or in year one, and the benefits are not really kicking in until later years (where the time-value of money discounting reduces the overall value of these benefits). NPV is great at tallying up the net benefits over an investment horizon so that different projects can be compared as to the value they return to the company, but this metric alone does not highlight how long it may take to achieve the benefits (as payback period does).

9 IRR is essentially the interest rate that the project can generate for the borrower, and is calculated as the discount value that when applied in the NPV formula drives the NPV formula to zero. Since IRR calculates the cash flow return for each project, investments in projects can be compared easily to other investment vehicles and to investment hurdle rates (returns vs. risks) established by the lender. But IRR is not a great indicator as to the magnitude of investment needed, benefit value or payback, so the returns may be high, but the investment high, benefits not significant and/or payback (risk) too high.

10 ROI and risk-adjusted ROI calculates the net benefits (total benefits – total costs) of a project divided by the total costs in a ratio to help highlight the magnitude of potential returns versus costs. An ROI of 150% means that $1 invested in the project will garner the investor $1 of their original investment back + $1.50 in gains. Risk-adjusted ROI is often recommended, as it tallies using the time value of money to discount the benefits and costs over time. Risk-adjusted ROI provides a more conservative ratio, since benefits are usually higher than costs in outgoing years, thus the benefits are discounted and the calculated ratio is lower. Businesses typically expect ROI of at least 100% to usually not more than 400% (although higher is possible). The ROI formula is great at comparing the costs to benefits in a ratio, but does not highlight well the timeliness of the returns, where payback period is better.