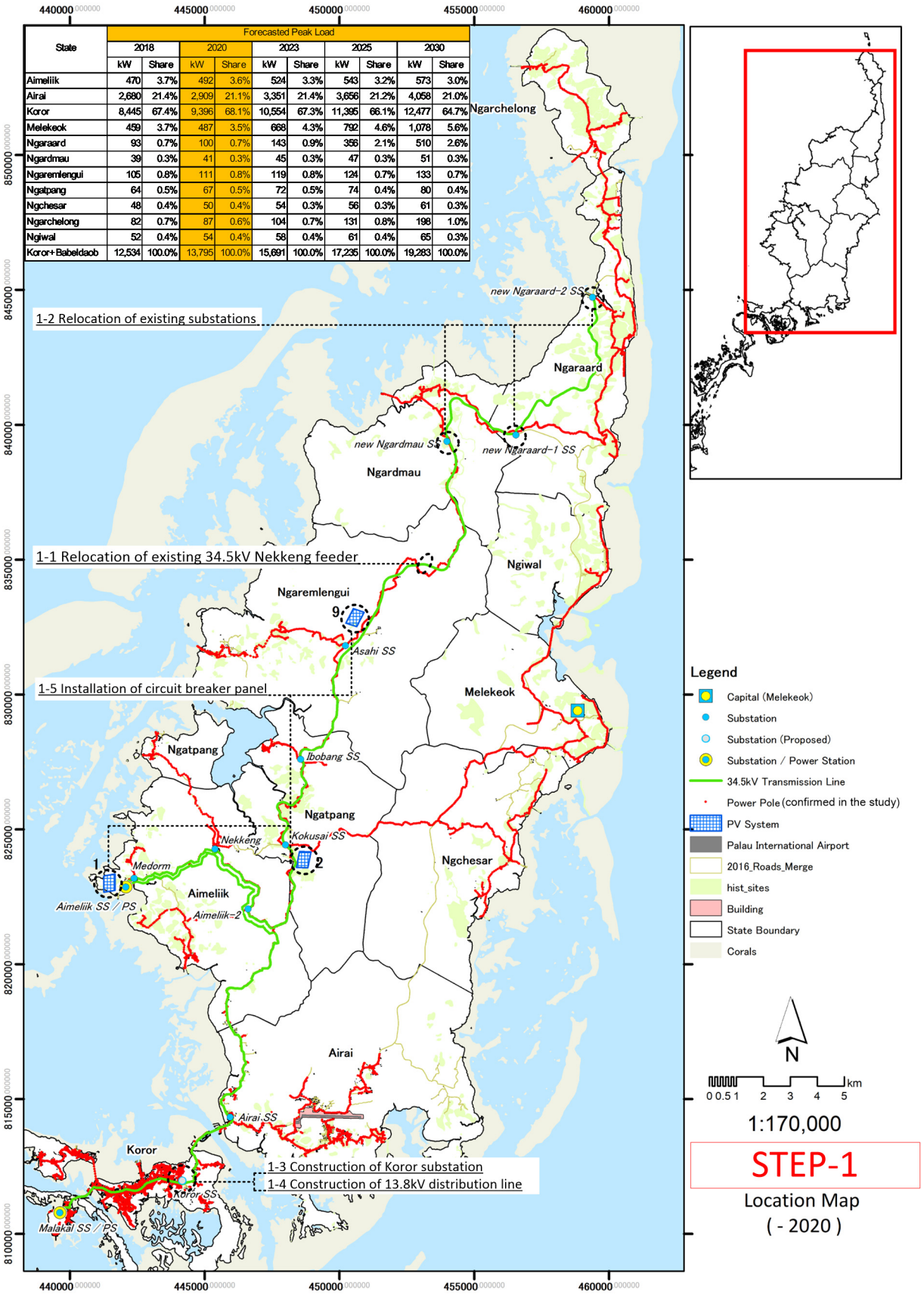


Figure 6-5.1 Expansion plan and location map (by 2020)

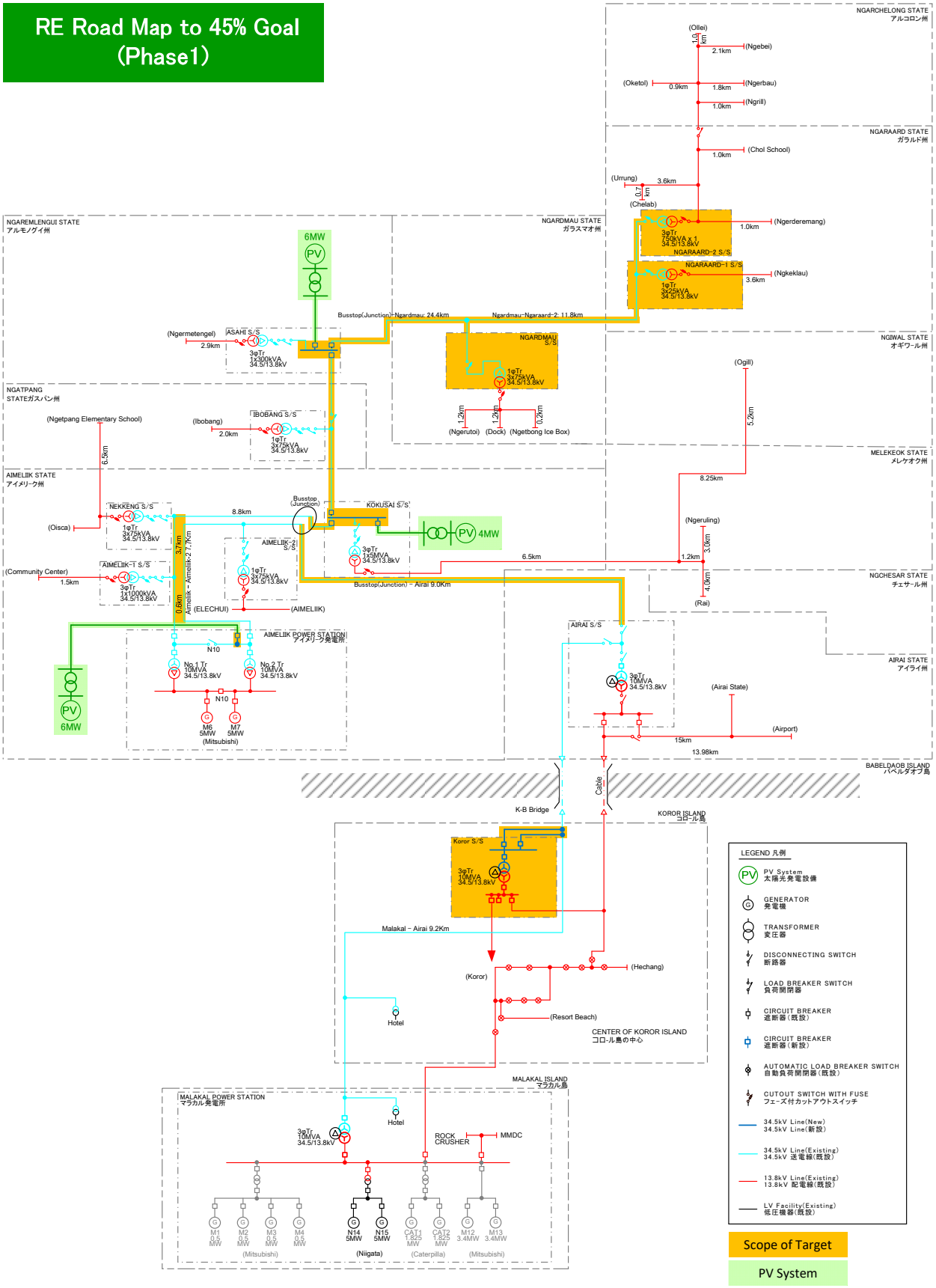


Figure 6-5.2 Network diagram (by 2020)

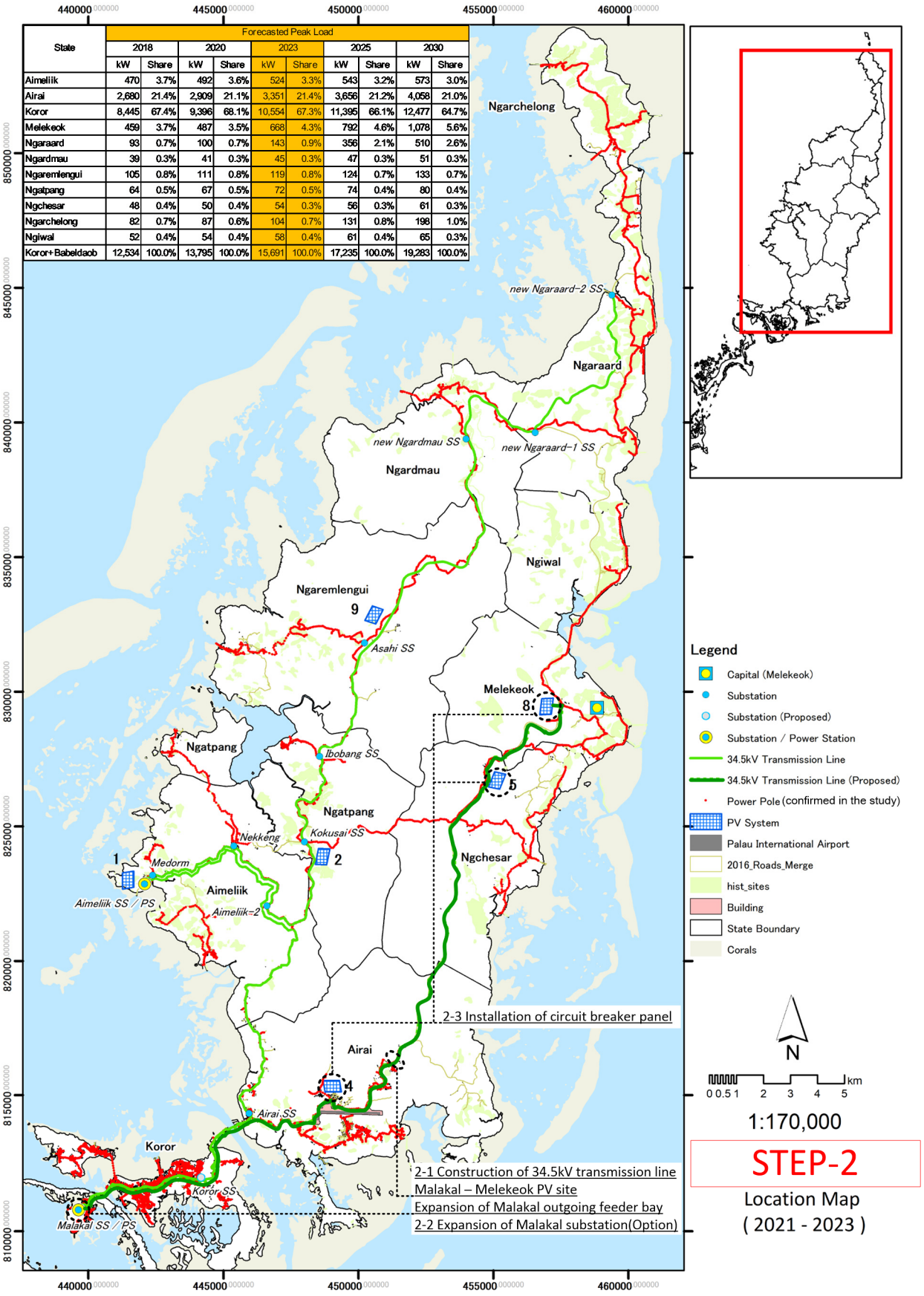


Figure 6-5.3 Expansion plan and location map (2021 – 2023)

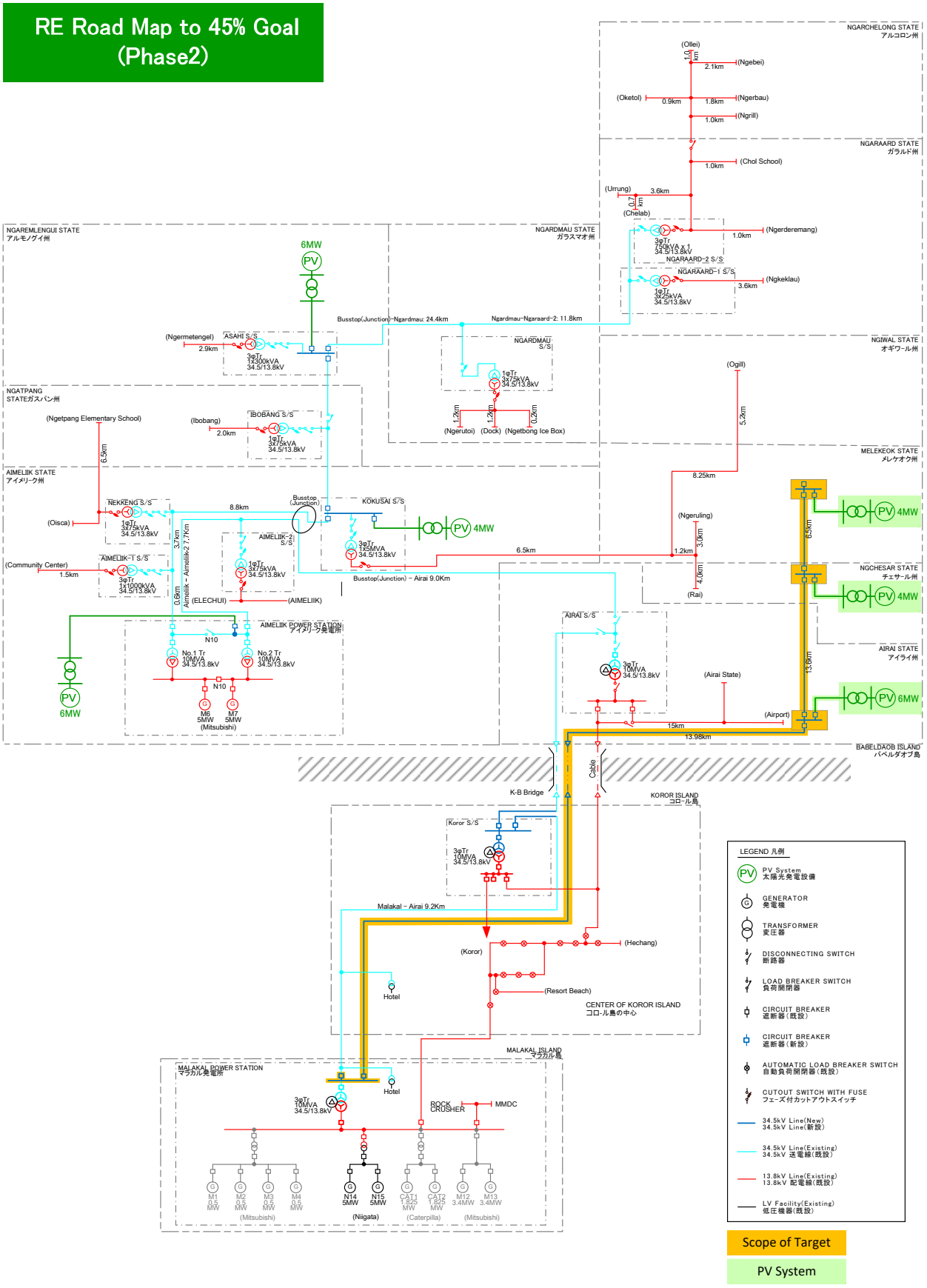


Figure 6-5.4 Network diagram (2021 – 2023)

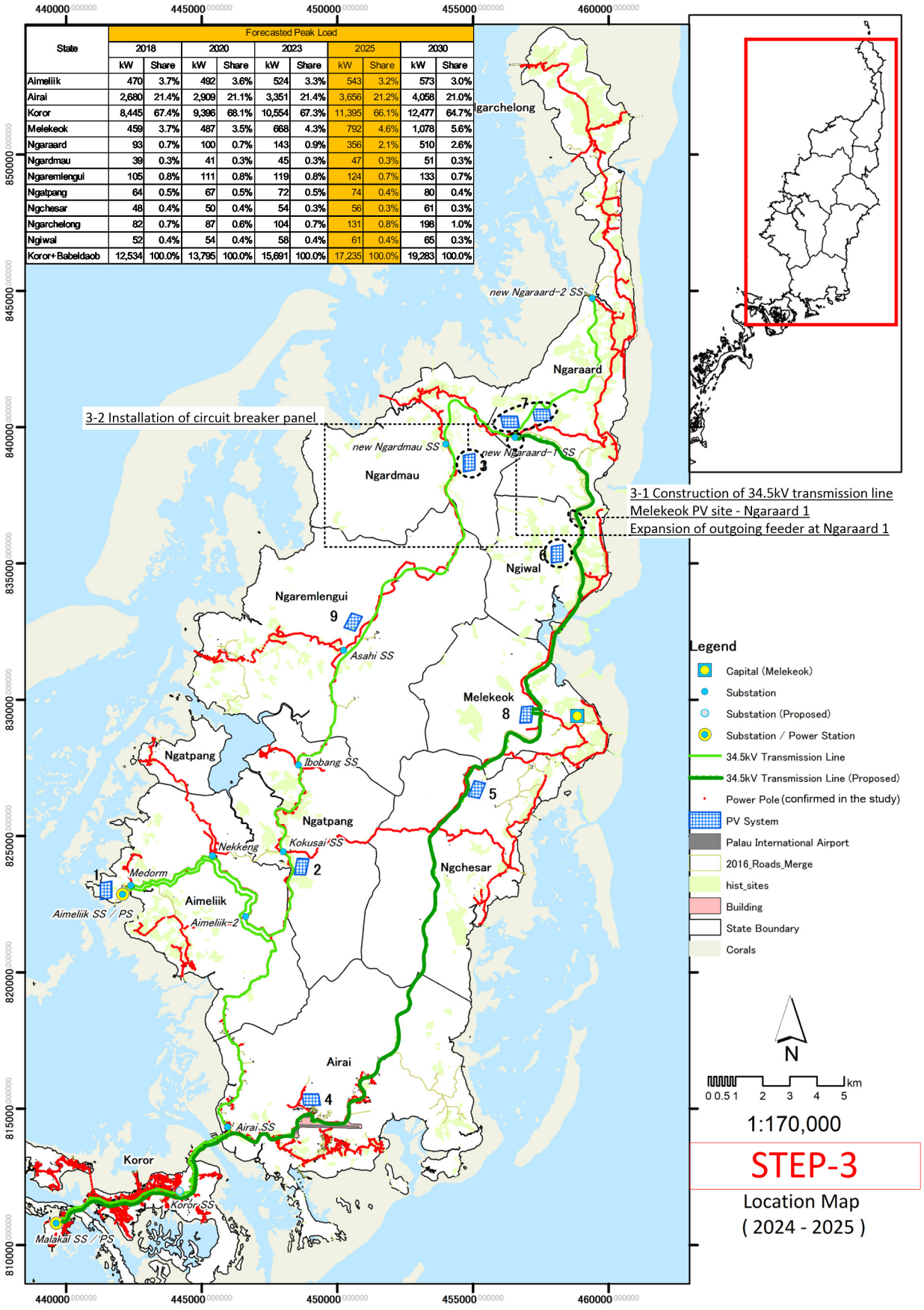


Figure 6-5.5 Expansion plan and location map (2024 – 2025)

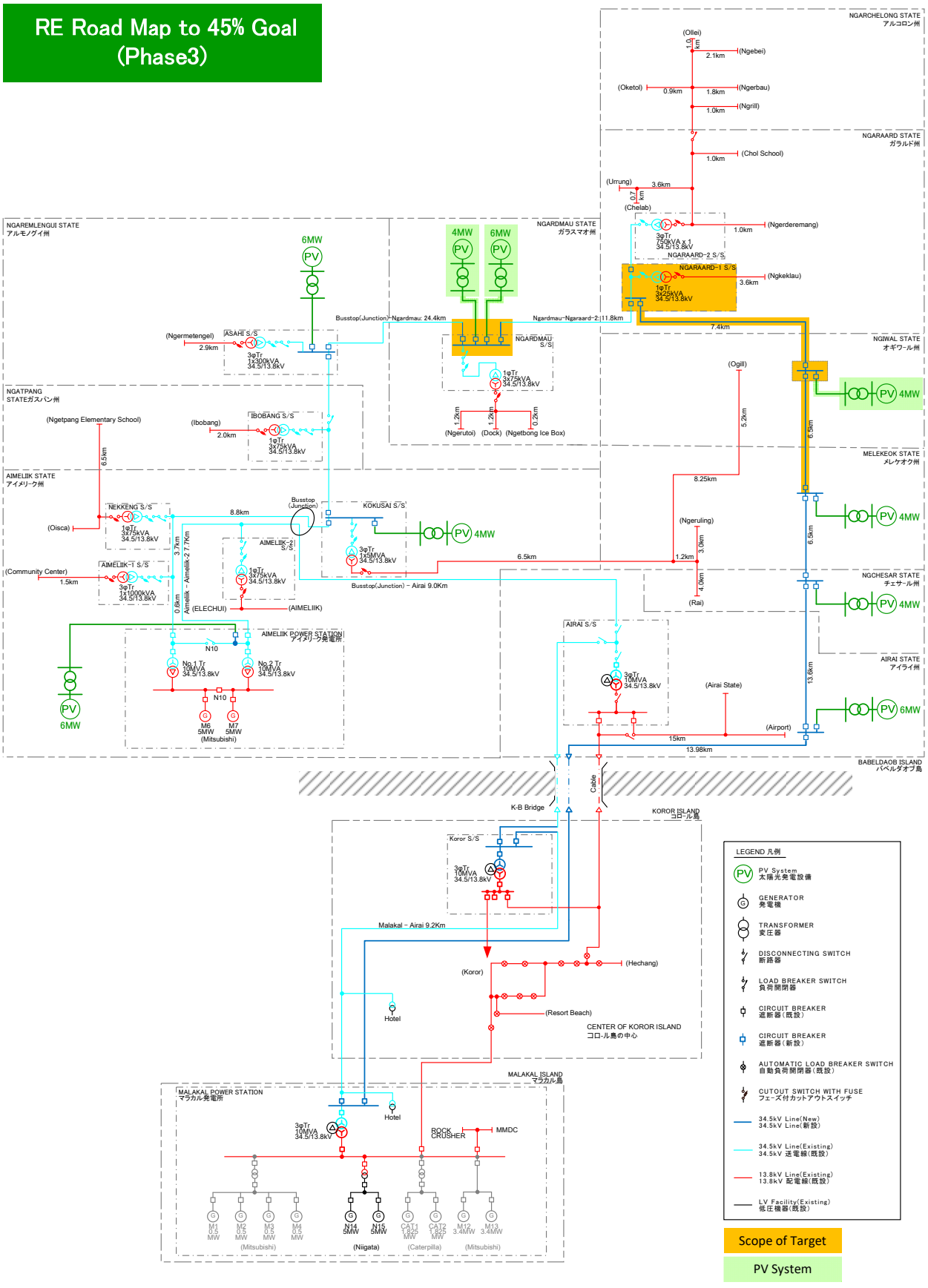


Figure 6-5.6 Network diagram (2024 – 2025)

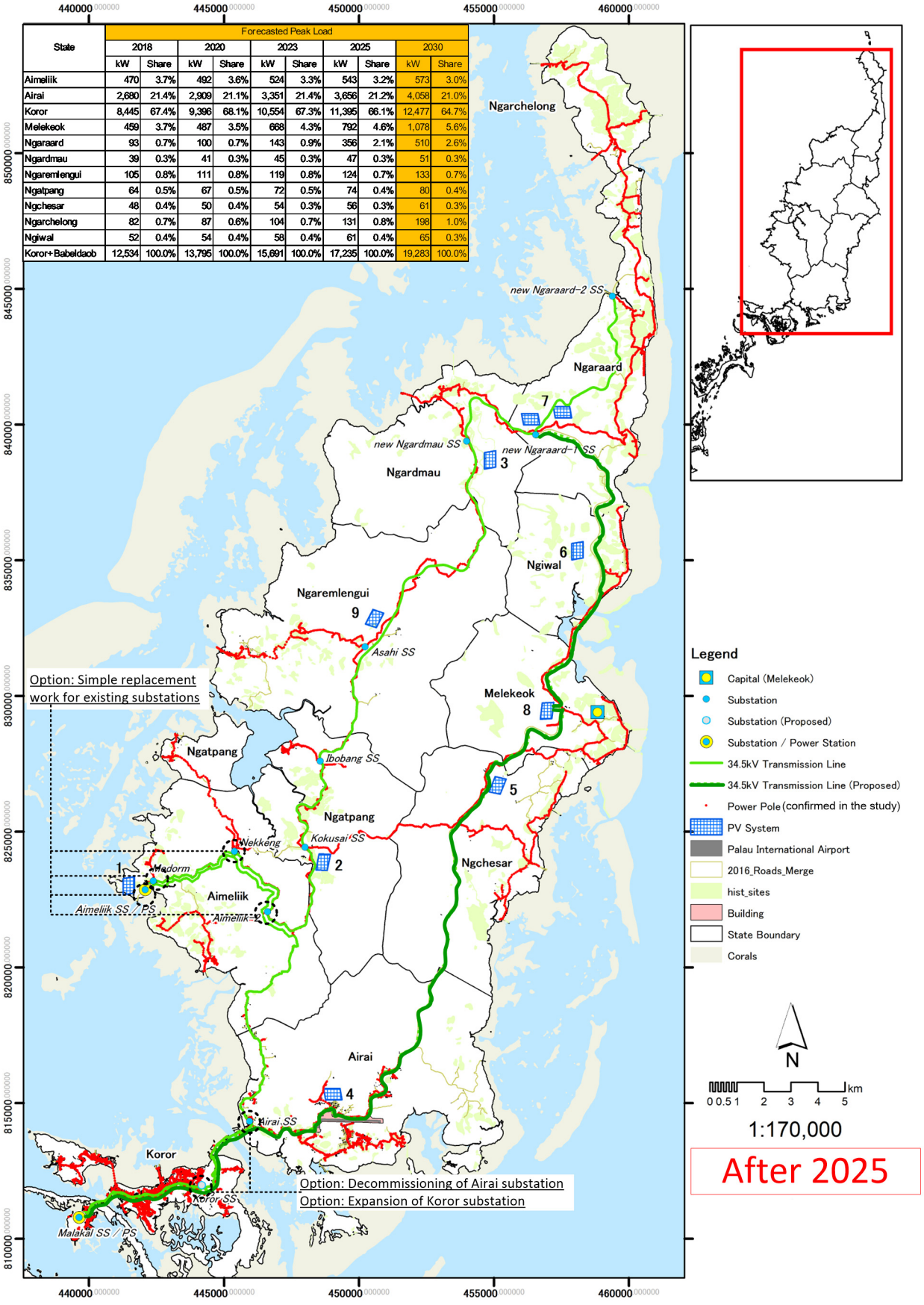


Figure 6-5.7 Expansion plan and location map (for reference after 2025)

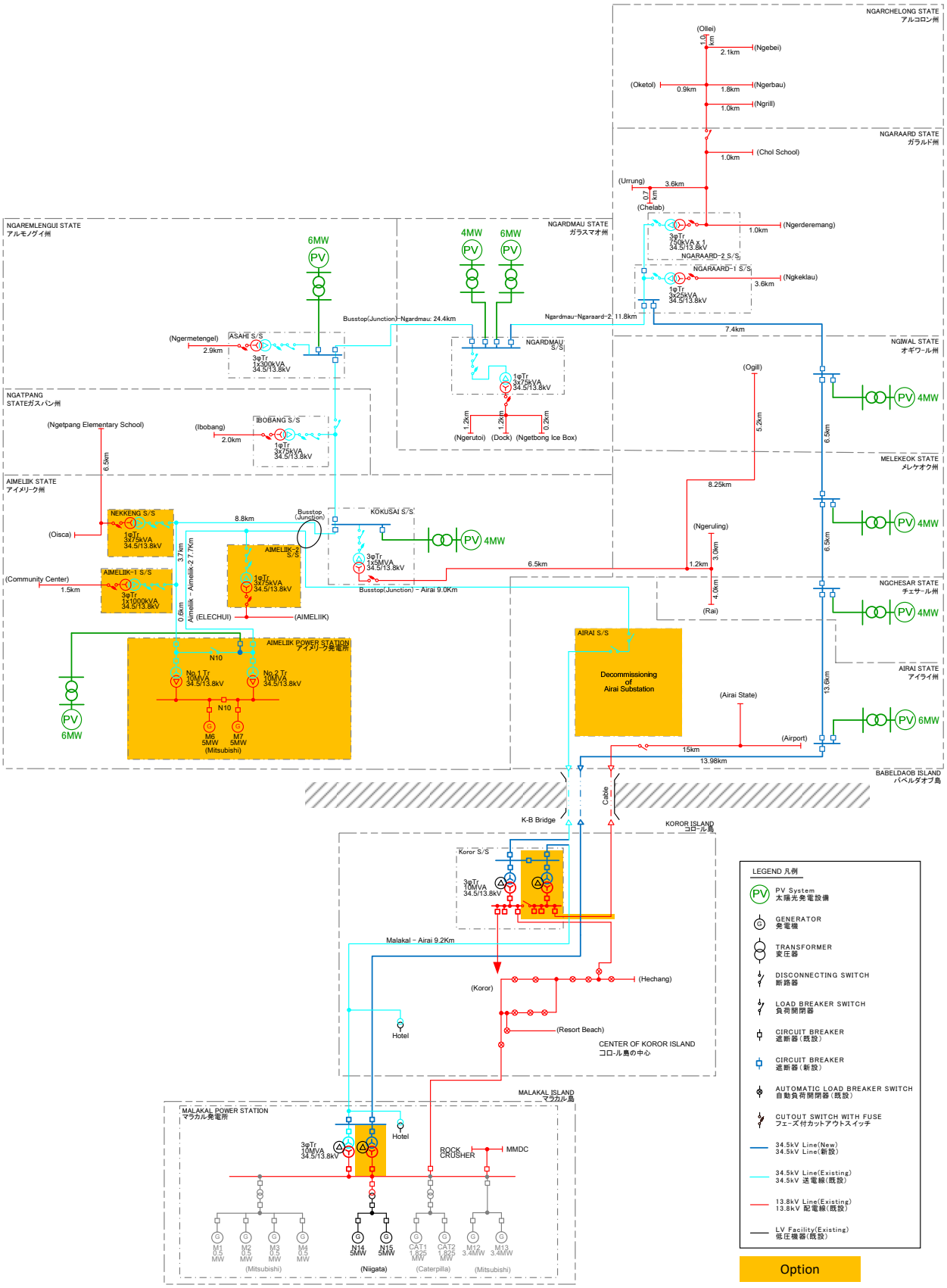


Figure 6-5.8 Network diagram (for reference after 2025)

CHAPTER 7 Environmental and Social Considerations

Chapter 7 Environmental and Social Considerations

7-1 Laws, Organizations, and Procedures Related to Environmental and Social Considerations

7-1-1 Laws, Regulations and Organizations

As a legal system on environmental and social considerations in Palau, the Constitution formulated in 1979 can be cited first. Article 6 of the Constitution, on the "Responsibility of the Government," sets the preservation of a beautiful, healthy and resource-rich natural environment as one of the national goals.

The Environmental Quality Protection Act, Palau's basic law on environmental preservation, describes four components of the country's basic environmental preservation policy:

(1) Fulfill the responsibility of each generation as a trustee of the environment for succeeding generations;

(2) Assure safe, healthful, productive, and aesthetically and culturally pleasing surroundings for all Palauan;

(3) Attain the widest range of beneficial uses of the environment without degradation, risks to health or safety, or other undesirable and unintended consequences; and

(4) Preserve important historical, cultural, and natural aspects of our Palauan heritage and maintain, wherever possible, an environment that supports the diversity and variety of individual choice.

The Environmental Quality Protection Act also regulates the composition of the Environmental Quality Protection Board (EQPB) and the creation of Environmental Impact Statements (EIS, described later). EQPB, the supervising body for environmental management and environmental impact assessment in Palau, is composed mainly of seven directors appointed by the president under the advice and agreement of the Senate. The term of a board member is three years.

EQPB regulations on sectors and criteria for evaluating environmental impacts include the following.

- Chapter 2401-01 Earthmoving Regulations
- Chapter 2401-11 Marine and Fresh Water Quality Regulations
- Chapter 2401-13 Toilet Facilities and Wastewater Disposal Systems Requirements
- Chapter 2401-31 Solid Waste Management Regulations
- Chapter 2401-33 Pesticide Regulations
- Chapter 2401-51 Public Water Supply System Regulations
- Chapter 2401-61 Environmental Impact Statement Regulations
- Chapter 2401-71 Air Pollution Control Regulations
- Chapter 2401-81 Ozone Layer Protection Regulations

Among these, the Air Quality Standard (Chapter 2401-71-05), a monitoring index for construction activities assumed in this project, is prescribed in Table 7-1-1.1. Compared to the WHO standard as an international standard, many of the reference values for items in the index are somewhat moderate.

Table 7-1-1.1 Air Quality Standard (Chapter 2401-71-05)

Pollutant	Levels not to exceed	Note	(reference) WHO standards
Sulfur Oxides	60 μg/m^3 (0.02 ppm)	Annual arithmetic mean	20 μg/m^3 (24-hour mean) 500 μg/m^3 (10-minute mean)
	365 μg/m^3 (0.12 ppm)	Maximum 24-hour concentration not be exceeded more than once a year	
	1,300 μg/m^3 (0.5 ppm)	Maximum 1-hour concentration not be exceeded more than once a year	
	650 μg/m^3 (0.25 ppm)	Maximum 4-hour concentration not be exceeded more than once a year	
Particulate matter	60 μg/m^3	Annual geometric mean	PM2.5: 10 μg/m^3 PM10: 20 μg/m^3 （annual mean）
	150 μg/m^3	Maximum 24-hour concentration not be exceeded more than once a year	PM2.5: 25 μg/m^3 PM10: 50 μg/m^3 （24-hour mean）
	360 μg/m^3	Maximum 8-hour concentration not be exceeded more than once a year	N/A
Carbon monoxide	10 μg/m^3 (9 ppm)	Maximum 8-hour concentration not be exceeded more than once a year	10 μg/m^3 （8-hour mean）
	40 μg/m^3 (35 ppm)	Maximum 1-hour concentration not be exceeded more than once a year	30 μg/m^3 （1-hour mean）
Photochemical oxidants	160 μg /m^3 (0.08 ppm)	Maximum 1-hour concentration not be exceeded more than once a year	120 μg /m^3 （8-hour mean）
Hydrocarbon	160 μg /m^3 (0.24 ppm)	Maximum 3-hour concentration not be exceeded more than once a year	N/A
Nitrogen Oxides	160 μg /m^3 (0.05 ppm)	Maximum 24-hour concentration not be exceeded more than once a year	40 μg/m^3 (annual mean) 200 μg/m^3 (1-hour mean)

Source: EQPB, WHO

The legal system concerning Strategic Environmental Assessment (SEA) has not been established as of October 2017. According to EQPB, the SEA-related measures carried out in the various projects implemented by international donors and others in the past have been limited to individual measures.

7-1-2 Environmental Assessment (EA) and Environmental Impact Statement (EIS)

The procedures and contents of environmental impact assessments in Palau are specified in the Environmental Impact Statement Regulations (Chapter 2401-61).

First of all, EQPB permission is required for any development activity related to earthmoving, the public drinking water system, marine and freshwater discharge, solid waste management, or air pollution.

The process of permission application, review, and approval is shown in Figure 7-1-2.1. To apply for permission from EQPB, the applicant must confirm the project component, submit a permission from the Historic Preservation Office (HPO), and submit documents showing land use rights and state permissions, after consultation with EQPB. If EQPB decides that Environmental Assessment (EA) is necessary, the applicant must submit the following information to EQPB, as stipulated in the Environmental Impact Statement Regulations.

- Identification of applicant;
- Identification of the agencies and organizations to be consulted in making the assessment;
- General description of the technical, economic, social, and environmental characteristics of the action;

- Summary description of the affected environment, including suitable and adequate descriptions of the location and site maps;
- Identification and summary of the major impacts and alternatives considered, if any; and
- Proposed mitigation measures, if any.

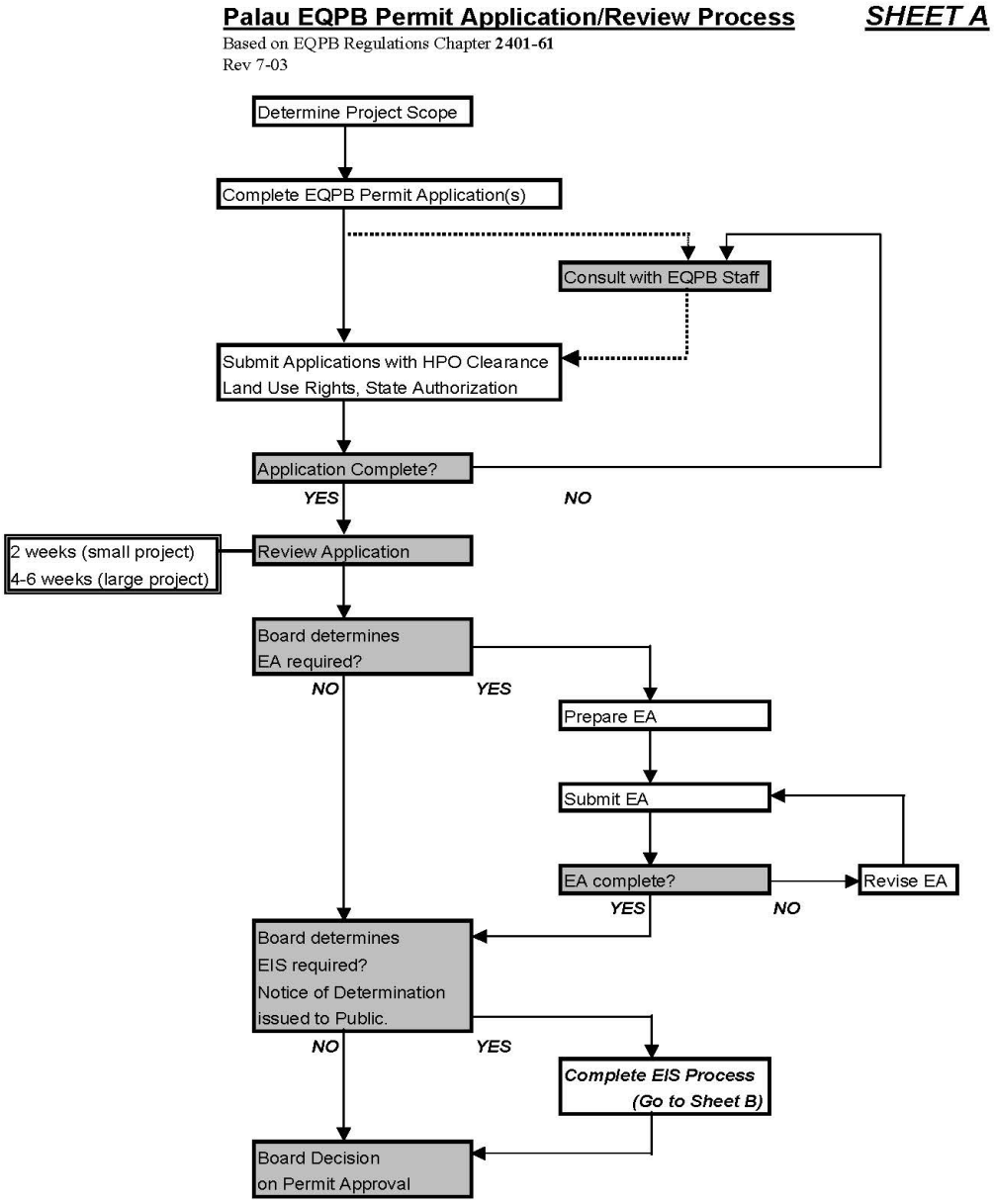
The Environmental Impact Statement Regulations require an EA for any project that targets national or state-owned land, uses public funds, is expected to affect protected areas / coastal areas / historic sites, or is deemed by EQPB to potentially have serious environmental impacts. EQPB also indicates that the period for the review and approval can be shortened by submitting the EA documents to EQPB at the beginning of the application process, regardless of whether the documents are necessary or required.

If EQPB decides, after the completion of an EA, that it will be necessary to prepare and review an Environmental Impact Statement (EIS), the EA will shift to the EIS process shown in Figure 7-1-2.2 and the environmental and social impacts of the target project will be examined more rigorously.

In evaluating the seriousness of the environmental impact of the target project, EQPB focuses on the following criteria prescribed in the Environmental Impact Statement Regulation (Chapter 2401-61 - 06 Significance Criteria):

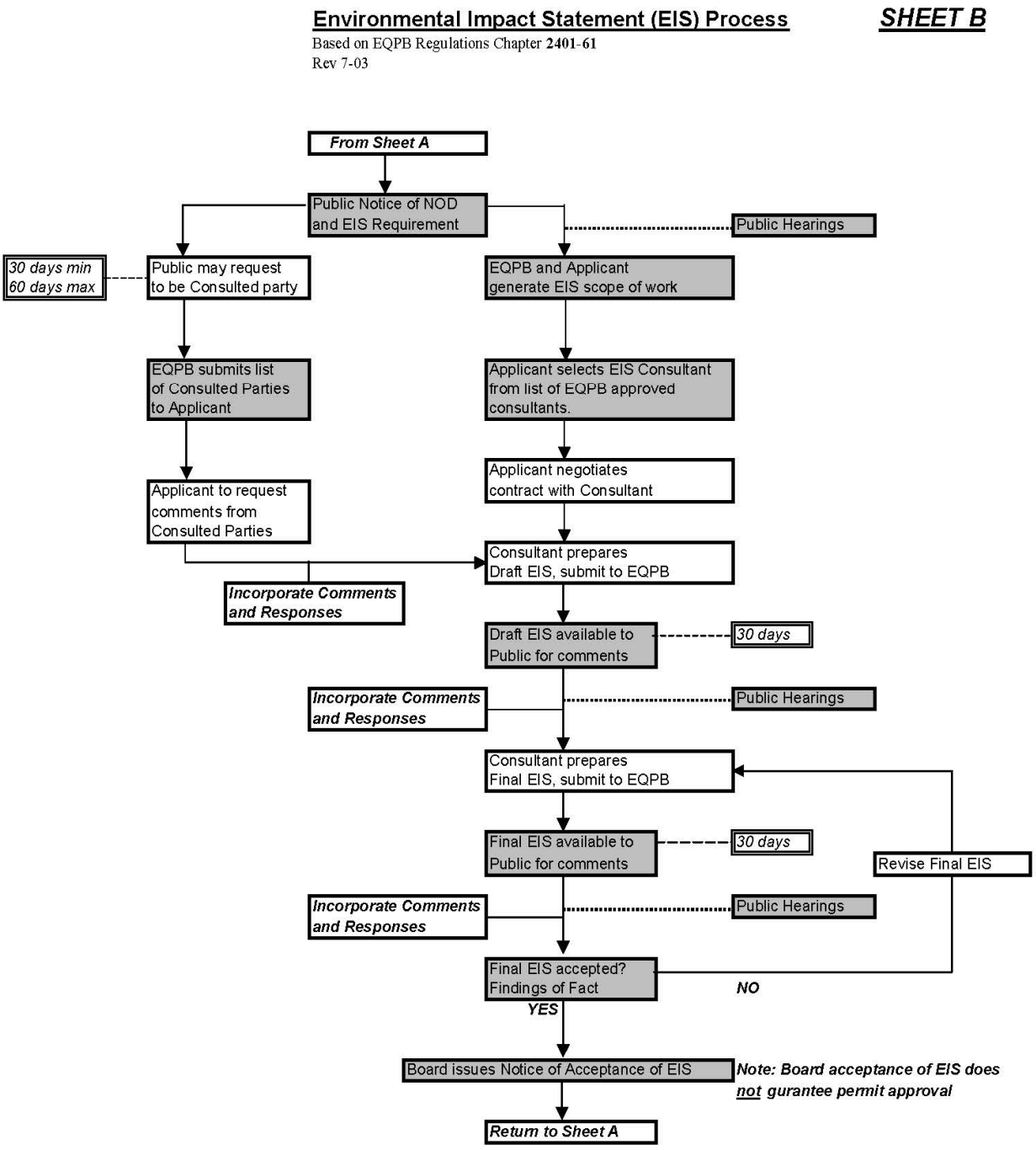
- Involves an irrevocable commitment to loss or destruction of any natural or cultural resource;
- Curtails the range of beneficial uses of the environment;
- Conflicts with the Republic of Palau's long-term environmental policies or goals and guidelines as expressed in the Environmental Quality Protection Act or any revisions thereof, amendments thereto, regulations promulgated thereunder, or relevant court decisions;
- Substantially affects the economic or social welfare of the community;
- Substantially affects public health;
- Involves substantial secondary impacts, such as population changes or effects on public facilities or infrastructure;
- Involves a substantial degradation of environmental quality;
- Is individually limited but cumulatively has considerable effect upon the environment or involves a commitment for larger actions;
- Substantially affects a rare, threatened or endangered species, or its habitat;
- Detrimentally affects air or water quality or ambient noise levels; or
- Affects an environmentally sensitive area such as a flood plain, erosion-prone area, geologically hazardous land, estuary, lagoon, reef area, mangrove swamp, fresh water, or coastal waters.

If an EIS is deemed necessary, the EIS consultant approved by EQPB is obliged to create an EIS. Multiple public hearings are held at the discretion of EQPB in the course of evaluating the EIS.



Source: EQPB

Figure 7-1-2.1 Process for applying for, reviewing, and approving environmental permits



Source: EQPB

Figure 7-1-2.2 Process for an Environmental Impact Statement (EIS)

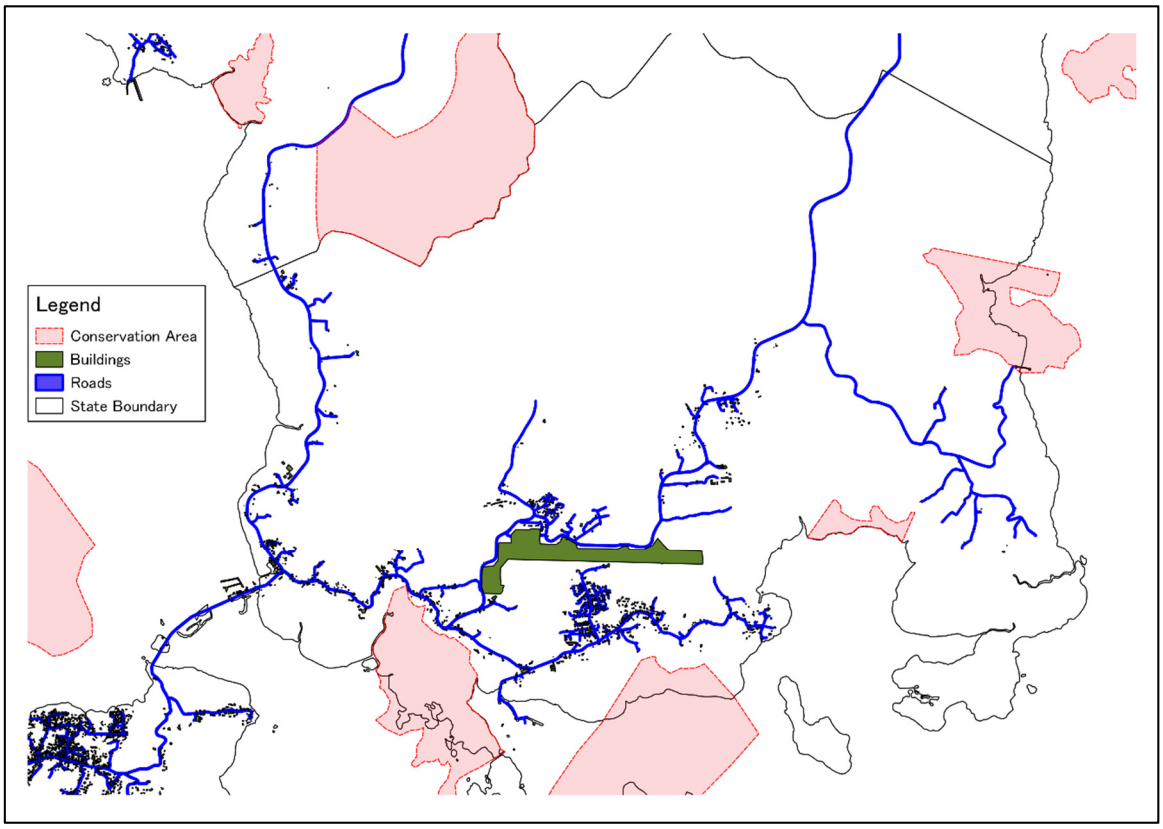
7-2 Current States of Natural and Social Environment in Palau

In this section, information collected on protected areas, historic sites, animals and plants are described as supplements to the contents of the detailed planning survey: environmental and social consideration report (February 2017)

7-2-1 Protected Area

Protected areas in Palau are distributed throughout the country to protect coral reefs, mangroves, sanctuaries of unique flora and fauna, etc. as prescribed in the Environmental Impact Statement Regulations. Development plans that may have environmental impacts on those areas have to be carefully examined.

In addition to information on protected areas stated in the detailed planning survey report[1], the JICA Project Team obtained GIS data (as of 2016) on protected areas prepared by the Palau Land Resource Information Systems Office (Office of the PALARIS). In considering the relocation and extension of transmission and distribution lines and the extension/renewal of substations in this project, GIS data can be used to confirm the overlap of protected areas and influences on adjacent protected areas in candidate sites with high accuracy. Figure 7-2-1.1 shows the distribution of the protected areas in the Airai State as an example.



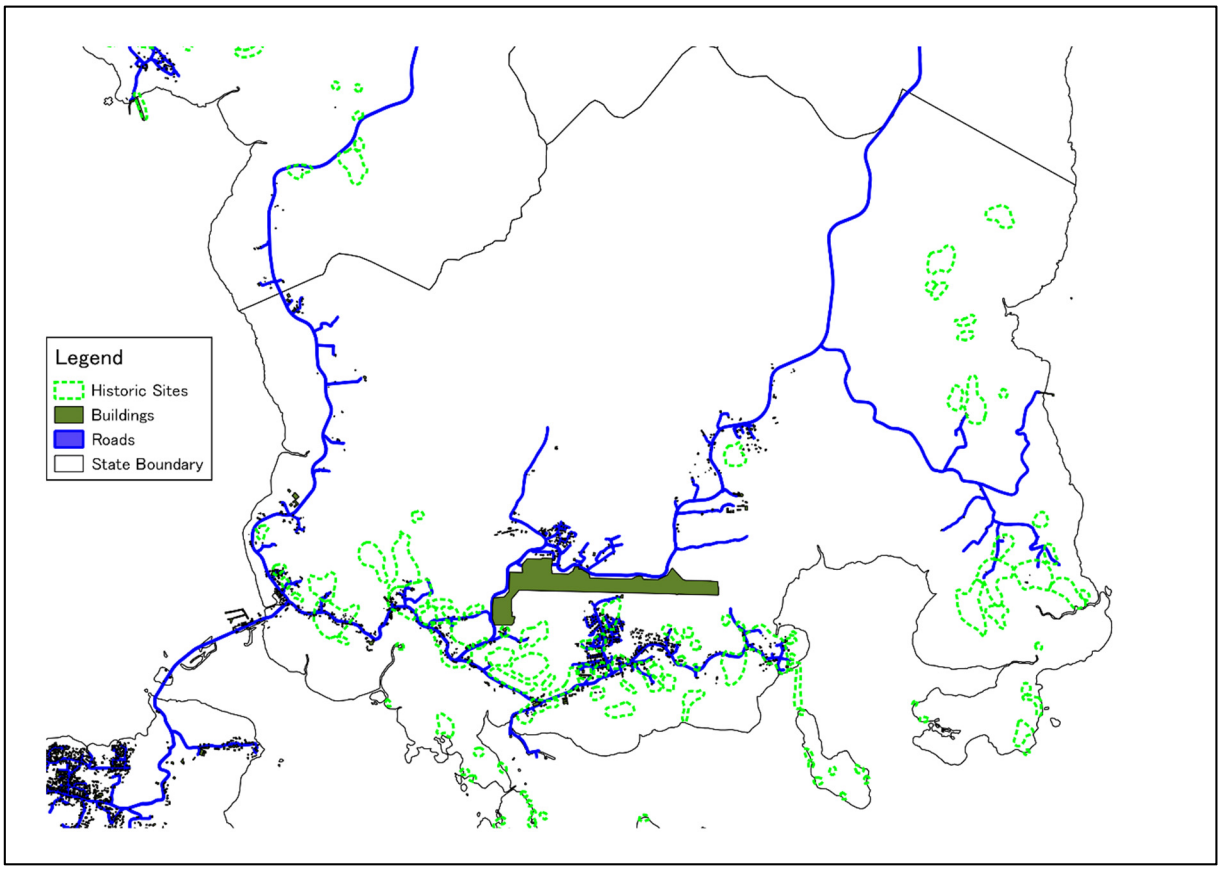
Source: Prepared by the JICA Project Team based on the map provided by the Office of the PALARIS

Figure 7-2-1.1 Distribution of protected areas in Airai State

[1] The Republic of Palau Revised National Biodiversity Strategy and Action Plan 2015-2025

7-2-2 Historic Sites

As with the data on the protected area described above, GIS data (as of 2016) on historic sites was also obtained from the Office of the PALARIS. Figure 7-2-2.1 shows the current state of the historical sites in Airai State as an example.



Source: Prepared by the JICA Project Team based on the map provided by the Office of the PALARIS

Figure 7-2-2.1 Distribution of historic sites in Airai State

7-2-3 Flora and Fauna

There are 27 types of animals in the Critically Endangered (CR) category and 28 species of animals and plants in the Endangered (EN) category in Palau. Together with the protected areas mentioned above, it will be necessary to consider these animals and plants when examining the development plan. The academic names and general names of the animals and plants are shown in Table 7-2-3.1.

Table 7-2-3.1 Animals and plants categorized as Critically Endangered (CR) and Endangered (EN) in Palau

Red List status	Kingdom	Genus	Species	Common names
Critically Endangered (CR)	Animalia	Aaadonta	angaurana	
		Aaadonta	irregularis	
		Aaadonta	kinlochi	
		Aaadonta	pelewana	
		Coneuplecta	turrita	
		Diplommatina	alata	
		Diplommatina	aurea	
		Diplommatina	crassilabris	
		Diplommatina	gibboni	
		Diplommatina	ringens	
		Eretmochelys	imbricata	Hawksbill Turtle
		Kubaryia	pilikia	
		Palaina	albata	
		Palaina	moussoni	
		Palaina	patula	
		Palaina	platycheilus	
		Palaina	pupa	
		Palaina	rubella	
		Palaina	striolata	
		Palaopartula	calypso	Great Palau tree snail
		Palaopartula	leucothoe	White Palau tree snail
		Palline	notera	
		Pseudopalaina	polymorpha	
		Semperdon	kororensis	
		Semperdon	xyleborus	
		Videna	pagodula	
		Videna	pumila	
Endangered (EN)	Animalia	Aaadonta	constricta	
		Aaadonta	fuscozonata	
		Anacropora	spinosa	
		Balaenoptera	musculus	Blue Whale
		Calidris	tenuirostris	Great Knot
		Cheilinus	undulatus	Giant Wrasse
		Chelonia	mydas	Green Turtle
		Diplommatina	inflatula	
		Diplommatina	pyramis	
		Elasmias	ovatulum	
		Emballonura	semicaudata	Pacific Sheath-tailed Bat,
		Holothuria	lessoni	Golden Sandfish
		Holothuria	nobilis	Black Teatfish
		Holothuria	scabra	Golden Sandfish
		Holothuria	whitmaei	Black Teatfish
		Hungerfordia	pelewensis	
		Megapodius	laperouse	Micronesian Scrubfowl
		Numenius	madagascariensis	Far Eastern Curlew
		Palaina	wilsoni	
		Palaopartula	thetis	Palau Pandanus tree snail
		Pectinia	maxima	
		Porites	eridani	
		Semperdon	uncatus	
		Sphyrna	mokarran	Great Hammerhead
		Stegostoma	fasciatum	Zebra Shark
		Thelenota	ananas	Prickly Redfish
		Videna	oleacina	
	Plantae	Cycas	micronesica	

Source: IUCN Red List (http://www.iucnredlist.org/)

7-3 Strategic Environmental Assessment (SEA)

7-3-1 Roadmap for renewable energy introduction

Table 7-3-1.1 shows the results of preliminary scoping on the PV panels, wind turbines, and storage batteries as the main components used for the introduction of renewable energy.

Negative impacts on air quality, noise, flora and fauna are expected in the construction stage, along with trends such as land acquisition, involuntary resettlement, human health hazard, the risk of accidents, etc. Extensive land is required for the installation of PV panels. It is also assumed that new roads and transmission lines will be constructed when wind turbines are installed. The negative impacts on the flora and fauna and negative impacts derived from land acquisition should therefore be carefully considered.

Although negative environmental and social impacts are generally small at the operation stage, negative impacts are expected from the rotational noise of the wind turbines and the risk of accidents when inspection and maintenance personnel climb high above the ground to work on the turbines.

Table 7-3-1.1 Results of preliminary scoping (solar panels, wind turbines, storage batteries)

Scoping items		Construction phase			Operation phase		
		PV Panel	Wind Turbine	Battery	PV Panel	Wind Turbine	Battery
Environmental	Air pollution	B-	B-	B-	D	D	D
	Soil pollution	B-	B-	B-	D	D	D
	Water pollution	C-	C-	C-	D	D	D
	Noise and vibration	B-	B-	B-	D	B-	C-
	Flora and fauna	A-	B-	B-	C-	C-	C-
	Preserved area	C-	C-	C-	C-	C-	C-
	Biodiversity	C-	C-	C-	C-	C-	C-
Social	Land acquisition/ involuntary resettlement	A-	B-	B-	D	D	D
	Influence on local economy	C-	C-	C-	Positive	Positive	Positive
	Human health hazard	B-	B-	B-	C-	C-	C-
	Risk of accidents	B-	B-	B-	C-	B-	C-

A-: Significant negative impact is expected. B-: Negative impact is expected.

C-: The extent of negative impact is unknown. D: No impact is expected.

Source: JICA Project Team

Based on the results of the preliminary scoping mentioned above, we conducted an environmental and social comparison and evaluation on alternative plans for the renewable energy introduction roadmap. The results are shown in Table 7-3-1.2. See Chapter 5 for technical details.

The combination of PV panels and wind turbines can reduce the scale of the site required for the entire power generation facility. On the other hand, the natural conditions suitable for wind turbine installation are very limited. There is also a high likelihood that separate sites will have to be secured for the installation of new construction access roads and transmission lines. Taking these factors into consideration, we judged that the first and third cases are relatively advantageous from environmental and social viewpoints.

Table 7-3-1.2 Comparative evaluation of the environmental and social aspects of the alternatives (renewable energy)

	Case 1	Case 2	Case 3	Case 4
Outline	PV panel Short-term battery Long-term battery	PV panel Short-term battery Long-term battery Wind turbine	PV panel Short-term battery	PV panel Short-term battery Wind turbine
Environmental aspect	Negative impact on flora and fauna	Negative impact on flora and fauna, negative impact from the construction of access roads to wind turbines and new transmission lines, noise during operation	Negative impact on flora and fauna	Negative impact on flora and fauna, negative impact from the construction of access roads to wind turbines and new transmission lines, noise during operation
Social aspect	Larger site required	Risk of accidents during wind turbine maintenance	Larger site required	Risk of accidents during wind turbine maintenance
Evaluation	++	+	++	+

Source: JICA Project Team

We examined the overlap between the candidate sites for installation of solar power generation systems and the distribution of protected areas and historic sites. The results are shown in Table 7-3-1.3.

Though there is no precise comparison on GIS data (the information on the candidate sites is entered as handwritten maps by PPUC), there are cases where protected areas, etc. are included within or in the proximity of the candidate sites. To make the candidate sites more concretely known in the future, it will be necessary to duly consider the impacts on the protected areas, etc.

Table 7-3-1.3 Distribution of protected areas and historic sites and overlap with candidate sites for solar power generation

No.	Site	Output	Area	Location	
				Preservation area	Historic site
1	Aimeliik (next to power plant)	5 MWp+1MWp	15 acres+α	-	Near
2	Ngatpang (Kokusai)	2-3 MWp+1MWp	8 acres+α	-	-
3	Ngardmau (Terrace of Hill)	2-3 MWp+1MWp	7 acres+α	-	Included
4	Airai Airport (side by road)	3 MWp+3MWp	8 acres+α	-	-
5	Ngchesar	3 MWp+1MWp	8 acres+α	-	-
6	Ngiwal	3 MWp+1MWp	9 acres+α	-	Near
7	Ngardmau	5 MWp+1MWp	15 acres+α	Near	Near
8	Melekeok	3 MWp+1MWp	9 acres+α	Included	-
9	Ngaremlengui	5 MWp+1MWp	18 acres+α	-	-
Total		33MWp+11MWp			

Source: JICA Project Team based on the material provided by PPUC

7-3-2 Transmission and distribution network planning

Based on the results of the preliminary scoping (Table 7-3-2.1), we conducted environmental and social comparisons and evaluations on alternative plans for transmission and distribution network planning. The results are shown in Table 7-3-2.2. See Chapter 6 for technical details.

The newly installed power distribution lines are basically expected to be constructed at public places along the

compact road (there is assumed to be almost no land acquisition or resident relocation) and to have very limited impact on the environmental and social aspects. The evaluation results basically stood at the same level as a whole, except for that for the third case, in which a negative impact on coral reefs was assumed.

Table 7-3-2.1 Result of preliminary scoping (transmission and distribution network, substations)

Scoping items		Construction phase			Operation phase		
		Expansion	Relocation	Rehabilitation	Expansion	Relocation	Rehabilitation
Environmental	Air pollution	B-	B-	B-	D	D	D
	Soil pollution	B-	B-	B-	D	D	D
	Water pollution	C-	C-	C-	D	D	D
	Noise and vibration	B-	B-	B-	D	D	C-
	Flora and fauna	B-	A-	C-	C-	C-	C-
	Preserved area	C-	B-	D	D	D	D
	Biodiversity	C-	B-	D	C-	C-	C-
Social	Land acquisition / involuntary resettlement	C-	B-	D	D	D	D
	Influence on local economy	C-	C-	C-	Positive	Positive	Positive
	Human health hazard	B-	B-	B-	C-	C-	C-
	Risk of accidents	B-	B-	B-	C-	C-	C-

A-: Significant negative impact is expected. B-: Negative impact is expected.

C-: The extent of negative impact is unknown. D: No impact is expected.

Source: JICA Project Team

Table 7-3-2.2 Comparative evaluation of environmental and social aspects of the alternative cases (transmission and distribution network)

	Case 1	Case 2	Case 3	Case 4
Outline	New transmission line along the existing transmission line (Malakal power plant – Kokusai substation), newly established supply transmission line (for Melekeok substation and the newly established airport substation)	Construction of a network that half-rounds the southern part of Babeldaob Island (for Melekeok substation)	Linkage by submarine cable (Malakal power plant - Aimelik power station), establishment of new power transmission lines (for Melekeok substation and the newly established airport substation)	Construction of a network that circles Babeldaob Island (9 solar power plants, Melekeok substation, airport substation)
Environmental aspect	Temporary negative impact at the construction phase	Temporary negative impact at the construction phase	Temporary negative impact at the construction phase, irreversible negative impact on coral reefs on the seafloor	Temporary negative impact at the construction phase
Social aspect	There is assumed to be no noticeable negative impact, as the construction will basically take place on public land.			
Evaluation	++	++	+	++ * If introducing solar power generation system, the other proposals are technically unsuitable

Source: JICA Project Team

7-3-3 Substation equipment

Based on the results of the preliminary scoping (Table 7-3-2.1), we conducted environmental and social comparisons and evaluations on the alternatives for the substation equipment. The results are shown in Table 7-3-3.1. See Chapter 6 for technical details.

Compared with the second case, where the site is uncertain and the uncertainty factor is large, the first and third plans receive relatively high evaluations because the location has already been identified and the uncertainties are more limited.

Table 7-3-3.1 Comparative evaluation of environmental and social aspects of the alternatives (substation equipment)

	Case 1	Case 2	Case 3
Outline	Rehabilitation of Airai substation (same location)	Rehabilitation of Airai substation (different location)	New construction of Koror substation
Environmental aspect	The historic site adjacent to the slope to be constructed needs to be co served. The landscape seen from the side along the Compact Road needs to be considered. There are no adjacent protected areas.	Although there are no protected areas near Koror Island, there are multiple historical sites. It will thus be necessary to select a location that will not affect the historical sites.	The candidate site and the surrounding area are not close to historical sites or protected areas.
Social aspect	There are no dwellings or other buildings in the target area. No involuntary resettlement due to land expansion is expected.	The site is still uncertain. In any case, the site to be acquired should not require measures as extensive as involuntary resettlement.	There are no dwellings or other buildings in the target site, and no involuntary resettlement is assumed. A PPUC review of the acquisition of the same site indicates that it will be easy to begin coordinating with the landowner.
Evaluation	++	+	++

Source: JICA Project Team

7-3-4 Environmental and social considerations related to relocation of transmission lines

In order to grasp the environmental and social issues related to relocation of the transmission lines considered in the Project, a field survey at the Nekken transmission line (west to northern part of Babeldaob Island) was conducted with PPUC officials in December 2017. Figure 7-3-4.1 shows the situation at the time of the field survey.

Most of the utility poles expected to be relocated are installed along the old road used before the compact road was constructed. (The old road is unpaved but permits the entry of vehicles.) To improve maintainability, PPUC also conducts logging about once a year for the excavation of the old road, obtaining an Earthmoving Permit from EQPB every time.

According to PPUC, a 7-ton crane car and small excavator are required to remove a utility pole. If the old road is usable this heavy equipment could also be brought in, which would render new access roads for construction unnecessary and suppress influences on the environment. The usual practice in relocation is to remove the utility poles completely, together with their concrete foundations, etc. On the other hand, some of the utility poles in mountainous areas and valleys where it is difficult to carry in heavy machinery are composed of numerous steel column pillars that can be dug out and transported by human power. These poles, therefore, can also be removed without maintaining access roads. For these, however, excavation by human power is still necessary even if the poles have foundations of concrete.

A zone spanning 24 ft (about 7.3 m) from the center line of the compact road is basically the official land of the government. No land acquisition is necessary, as the relocation destination falls within that range and there is no need for permission from EQPB, etc. to cut down trees after the power transmission lines are transferred. In addition, an on-site inspection has confirmed that there are few existing buildings at the relocation destination. There is also a margin of space sufficient to avoid buildings by design, so no resettlement relocation is assumed to be necessary. Although the utility poles at the relocation source are also distributed in multiple protected areas, access by vehicle was possible in the protected area visited this time. The instructions from EQPB state that it will be necessary to minimize tree trunks and the cutting of branches and leaves during maintenance. In the case of relocation work in the protected area, it will be necessary to minimize the influence on animals and plants by making advanced adjustments with EQPB using heavy machinery according to the existing road conditions, human power, etc.

Chapter 10 describes the detailed results of the inspections of the actual conditions at the sites and the candidate sites explored for the priority project.

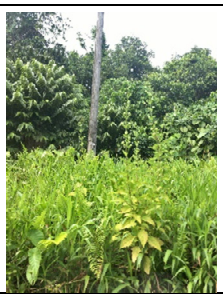
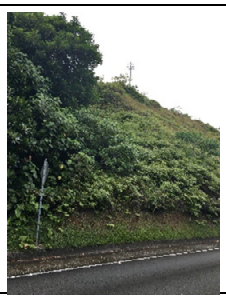
		
Utility pole installed along the old road	Site of a landslide along the old road	Vehicles entering the old road
		
Bird reserves in Aimelik State	Utility pole in the bird reserves	High-level utility pole that is difficult to access

Figure 7-3-4.1 Field survey at candidate sites for transmission line relocation (December 2017)

7-3-5 Proposed environmental and social impact mitigation measures and monitoring system

Table 7-3-5.1 shows the expected environmental and social impact avoidance/mitigation measures formulated based on the aforementioned scoping and evaluation results and on-site survey results. A development site location that avoids or mitigates environmental and social impacts and a basic design that takes stakeholders' opinions into account should be considered as thoroughly as possible at the stage of the SEA. Avoidance/mitigation measures that can be taken prior to the construction stage (shown in bold) are particularly important.

Table 7-3-5.1 Expected environmental and social impact avoidance/mitigation measures

Item		Avoidance/mitigation measure
Environmental	Air pollution	・ Appropriate operation and management of construction activity ・ Installation of countermeasures against noise and vibration at construction sites (e.g., soundproof sheets, etc.)
	Soil pollution	
	Noise and vibration	
	Flora and fauna	・ **Careful consideration on the location of development site and basic designs to avoid/mitigate environmental and social impacts as much as possible** ・ **Examination of an optimal plan to minimize unavoidable environmental and social impacts, in consideration of stakeholder opinions** ・ Recovery of the natural environment by backfilling, afforestation, etc.
	Preserved area	
	Biodiversity	
Social	Land acquisition/ involuntary resettlement	
	Human health hazard	・ Careful consideration of occupational health conditions at construction sites
	Risk of accidents	・ Implementation of safety control measures, preparation and training for accidents (e.g., evacuation, firefighting, etc.)

Three responsible organizations are named in the proposed monitoring system, stage by stage: PPUC 's Project Planning & Implementation Department in the planning stage, contractors in the construction stage, and PPUC in the operation stage. EQPB oversees these responsible organizations through the planning, construction, and operation phases. PPUC also regularly reports the status of monitoring to EQPB and shares the same among stakeholders, as necessary.

These proposals were shared with the parties concerned on the Palau side at the Joint Coordination Committee implemented locally on April 13, 2018.

7-4 Stakeholder's meeting

7-4-1 First Stakeholder's meeting

The JICA Project Team prepared for the stakeholder's meeting on SEA by consulting with PPUC and EQPB after the first field survey of July 2017 and fixing the schedule, presentation contents, and stakeholders in the second field survey of October 2017. The following stakeholders were selected through the consultation with PPUC and EQPB:

- EQPB
- Historic Preservation Office
- Office of the PALARIS
- Chamber of Commerce
- Palau Conservation Society

・State Government
・House of Traditional Leaders
・MPIIC/PPUC
・JICA/JICA Project Team

Though PPUC has emphasized the importance of the State Government and House of Traditional Leaders as stakeholders, it would be difficult to invite such highly placed political bodies at present, before the master plan has materialized. PPUC will therefore be collecting comments and opinions from these two organizations, separately from the stakeholder's meeting, after the substantive details of the master plan and priority project have been decided.

The first stakeholder's meeting was held in the meeting room of the PPUC – Water and Wastewater Operation Office on October 23, 2017. Some of the stakeholders, however, had travelled to the capital on the day of the meeting, as another governmental conference was scheduled to be held the following day. Some of the prospective attendees from external organizations were therefore absent from the meeting.

The JICA Project Team began the meeting by outlining the SEA, candidate priority projects, results of the preliminary scoping, and so on to the participants, PPUC staff, and JICA senior volunteers. The participants were also apprised of a GIS analysis using GIS data on protected areas and historical sites near the Nekken transmission line to grasp and evaluate expected environmental and social impacts at specific sites. PPUC agreed to share the distribution materials among the stakeholders not in attendance, and to later collect comments.

The second stakeholder's meeting was supposed to be held in early December. However, as a result of consultation with JICA and the examination in the JICA Project Team, consideration of development options taking into account the introduction of renewable energy seems to take more time than the original schedule. As a result, as discussed in the pre-dispatch meeting on November 2, 2017, the 2nd stakeholder's meeting did not necessarily have to be held during the third field survey in late November – early December 2017. Rather, the 2nd meeting was to be held after the development alternatives were examined from a renewable energy context. The meeting was to be held in whatever format that proved to be feasible (e.g., as a request for the comments and opinions of the respective stakeholders, etc.).

7-4-2 Second Stakeholder's meeting

A 2nd Stakeholder's meeting was to be held during the 4th field survey period. Preparations for the meeting commenced from the beginning of March 2018, but the timing of the meeting and stakeholder affairs ultimately made it difficult to hold the meeting in a conventional conference format. Instead, we shared the results of the Strategic Environmental Assessment (SEA) with the stakeholders in advance and sounded out comments directly from EQPB and the Palau Conservation Society by holding individual interviews whenever possible during the 4th field survey period.

The comments and suggestions from EQPB are shown below.

・ There were no objections to the results of the SEA, including the environmental impact avoidance/mitigation measures and proposed monitoring system.

- The contents of the project should be discussed with the State Government as soon as possible (before the basic design stage) before application for environmental permits. Given that EQPB is to share the contents of the application with the State Government after the application is accepted, the process of obtaining the State Government's permission and reviewing the environmental permission will be smooth if the applicant is able to consult with the State Government in advance.
- Originally, an Earthmoving Permit from EQPB was necessary when logging trees by the old road along the compact road. PPUC, however, incurred a fine by harvesting trees several times without permission for transmission line maintenance. EQPB expects PPUC to apply for any and all permits necessary before transferring or stretching the transmission line.
- The cutting of trees at the construction stage should be kept to a minimum in all projects. If there are vulnerable places such as water sources or coasts, EQPB expects the contractors to pay particular attention to the environmental impact.
- Consultations with stakeholders on both environment and social factors were conducted every quarter during the implementation of the PPUC water supply project. EQPB recommends the regular sharing of information with related parties at the stage of project implementation.

The comments and suggestions from the Palau Conservation Society, the largest environmental NGO active at the site, are shown below.

- Phosphorus in the soil makes it difficult for plant cover to grow in the old phosphorus mines distributed mainly in Ngardmau, which makes the soil vulnerable to erosion. If these sites are covered in some way and PV panels can be placed on them, the land can be utilized while preserving the soil from erosion.
- Though not large in scale, the Palauan tropical rainforest is one of the world's important natural heritages to be protected, with many bird (25 to 30 species) and plant species threatened with extinction. When selecting PV sites, the conservation of the tropical rainforests must be carefully considered.
- Any tree cutting by PPUC must be performed within the appropriate range during transmission line construction and maintenance (within the range of official land along the public road or where Earthmoving Permits from EQPB have been acquired). PCS is ready to cooperate with PPUC to ensure so that we can properly remove trees according to an appropriate vegetation management plan.
- Project activities at the candidate sites of the newly constructed substation (Koror) and relocation destinations (Ngardmau, Ngaraard 1, Ngaraard 2) are expected to have little direct negative impact on the environment. Negative impact that can occur indirectly, however, should be kept in mind. A newly constructed substation, for example, could conceivably change the route of rainwater drainage during heavy rains. Negative impacts on the bay area (e.g., Airai Bay) subject to conservation could also occur, though a properly designed and maintained rainwater drainage channel would preempt this problem.

The results of the Strategic Environmental Assessment (SEA) and outcome of the consultation with the stakeholders were shared with the parties concerned on the Palau side at the Joint Coordinating Committee held on April 13, 2018.

CHAPTER 8 Finance and Economic Analysis

Chapter 8 Finance and Economic Analysis

8-1 Summary of Finance and Economic Analysis

The Palau Public Utility Corporation (PPUC) is a public corporation established to manage and operate the electric power operation (EPO) and water and wastewater operation (WWO) of the Republic of Palau. PPUC runs its business by a form of autonomous management approved by the government.

The PPUC Board of Directors consists of seven directors appointed by the President with advice and consent from the Senate. It is an agency under the direct control of the executive office of the President and is the only energy supply company in the Republic of Palau.

This chapter will summarize 1) the current financial situation of PPUC, 2) an economic analysis of the master plan based on an assumed renewable energy (RE) ratio of 45% in 2025, and 3) an analysis of the introduction of IPPs (Independent Power Producers) in Palau.

(1) Summary of the financial analysis

Capital and capital surplus, which are capital items on the balance sheet of the PPUC electric power business, are too small to fund the large capital investments necessary for ongoing business growth in the future. The current PPUC electricity fee, which is set based on the fuel cost (Fuel) and business operation cost (Energy), falls well short of a level that would allow PPUC to accumulate sufficient retained earnings. To achieve mid- to long-term business operations without depending on government subsidies and financial support from international donor agencies, it will be important to accumulate profits necessary for capital investment through electric power sales income and to add a profit margin to that for the electricity tariff.

(2) Summary of the economic analysis

The PV generation cost is lower than the cost of the current diesel engine generator (DEG). Also, PV generation cost is steady comparing with DEG generation that rely on the fuel. Palau may be able to supply PV power to the end consumer more inexpensively versus DEG at the time of fuel shortages. It will therefore be reasonable, from a managerial point of view, for PPUC to make a full-scale entry into RE through PV as a power business operator.

(3) Summary of the analysis of IPP introduction

With the introduction of IPPs, the possibility of achieving the Palau national goal of RE 45% becomes more feasible. The total PV investment required for this project is an easily investable amount for a large IPP operator, and the financial burden of PPUC and the Palau government is greatly reduced by the introduction of IPPs. Meanwhile, IPP introduction requires an electricity wholesale price that meets the investment return level of private enterprises.

8-1-1 Electric Power Tariff, Revenue and Supply

8-1-1-1 Method for fixing the tariff rate

In accordance with the automatic fuel price adjustment clause of the Electricity Service Law (2012), the power fee of PPUC is based on the maintenance and management cost (Energy) and fuel cost (Fuel), with the full-cost recovery method applied. The fee is set for each customer category (usage classification for general residence and commercial/government) and reviewed every quarter (Table 8-1-1-1.1).

Energy, which is subject to the operation and maintenance costs shown in the following price list, have not changed since 2012, while Fuel has been reviewed and changed every quarter according to the change of the diesel price level.

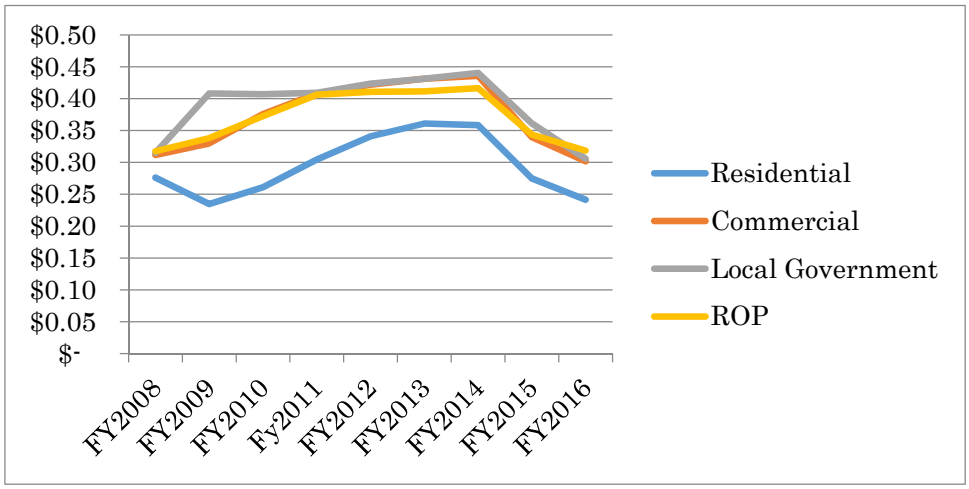
Table 8-1-1-1.1　Tariff table for customer categories, January 2018）

EPO Tariff Schedule				
Effective July 1, 2017				
Band	**kWh**	**Energy**	**Fuel**	**Rate**
1 - Res	0 - 150	0.020	0.177	0.197
2 - Res	151 - 500	0.094	0.177	0.271
3 - Res	501 +	0.143	0.177	0.320
Com/Govt	0 - 150,000	0.143	0.177	0.320
Com/Govt	150,001 - 250,000	0.133	0.177	0.310
Com/Govt	250,001 +	0.123	0.177	0.300

Res, Residential; Com, Commercial; Govt, Government
Source: PPUC Schedule of Electric Service Rates, July 2018

8-1-1-2 Recent level of tariff rate

The average electricity-selling tariff rate for all customer categories (general residential, commercial, local government, central government) has declined, reflecting the recent crude oil price peak in 2014 (see Figure 8-1-1-2.1).

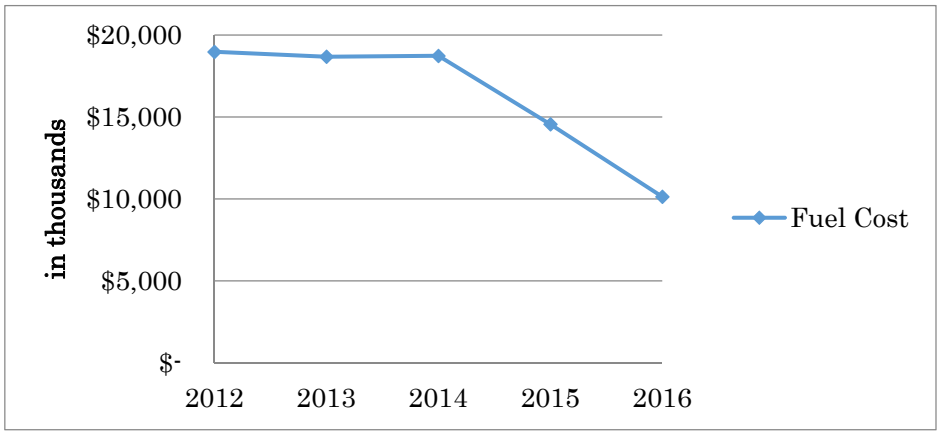


Source: Study Team

Figure 8-1-1-2.1 Average tariff rate for each customer category (US$)

8-1-1-3 Revenue and supply

Reflecting the decline in crude oil prices, the fuel cost of the electric power business in the year 2016 has decreased by 47% from 2012 (Figure 8-1-1-3.1).



Source: Study Team

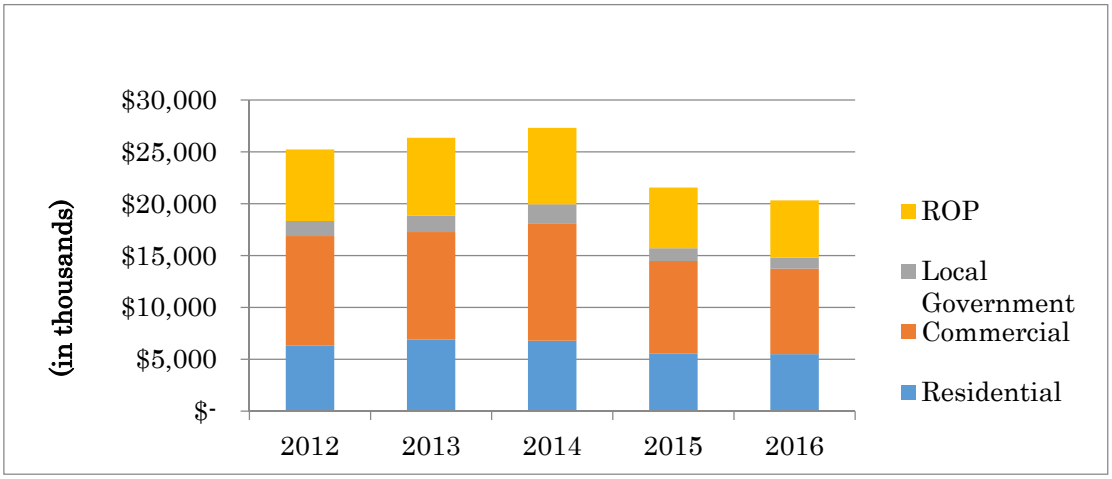
Figure 8-1-1-3.1 Fuel Cost（US$, 000）

Due to price reductions reflecting lower fuel costs, sales have declined since 2014 (Table 8-1-1-3.1). The proportion of sales to commercial sales currently stands at about 40% for commercial use, 30% for general residential, and 30% for government affairs. No significant change in the sales ratio has taken place in recent years (see Figure 8-1-1-3.2).

Table 8-1-1-3.1 Revenue（US$, 000）

	FY2012	FY2013	FY2014	FY2015	FY2016
Residential	6,350	6,912	6,800	5,569	5,500
Commercial	10,531	10,358	11,260	8,910	8,237
Local Government	1,459	1,581	1,872	1,225	1,069
ROP	6,898	7,509	7,377	5,852	5,526
Total	25,238	26,360	27,309	21,556	20,332

Source: Study Team, based of PPUC data



Source: Study Team, based of PPUC data

Figure 8-1-1-3.2 Change of the proportion of sales

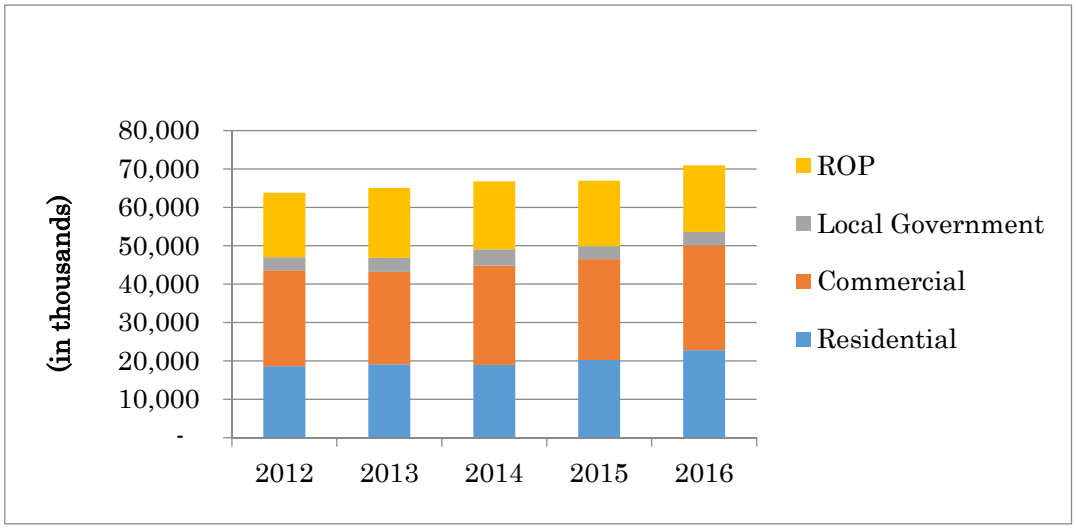
The electricity sales volume in 2016 was 11% higher than that in 2012 (annual average growth rate 2.6%).

The sales volume for commercial use accounts for about 40% of the total (Table 8-1-1-3.2, Figure 8-1-1-3.3).

Table 8-1-1-3.2 Sales volume（kWh, 000）

	FY2012	FY2013	FY2014	FY2015	FY2016
Residential	18,629	19,147	18,970	20,263	22,791
Commercial	24,950	24,017	25,841	26,235	27,297
Local Government	3,445	3,666	4,252	3,392	3,498
ROP	16,793	18,252	17,712	17,033	17,343
Total	63,817	65,082	66,775	66,923	70,929

Source: Study Team, based of PPUC data



Source: Study Team, based of PPUC data

Figure 8-1-1-3.3 Sales volume（kWh, 000）

8-1-1-4 Cost of generation, cost of electricity, and average revenue from electricity

Table 8-1-1-4.1 below shows the power generation cost, total electricity power supply cost, and selling price of electricity (average value, per US $ / kWh). In 2012 and 2015, the average power supply cost per kWh was higher than the average selling price. According to PPUC, the facility renovation cost exceeds the expected cost and is not reflected in the selling price.

Table 8-1-1-4.1 Cost of generation, cost of electricity, and average selling price of electricity (Average, US$/kWh)

	FY2012	*FY2013*	*FY2014*	*FY2015*	*FY2016*
Cost of Generation (kWh)	0.38	0.38	0.38	0.33	0.22
Cost of Electricity (kWh)	0.41	0.40	0.40	0.35	0.26
Average Revenue from Electricity (kWh)	0.40	0.41	0.41	0.32	0.29

Source: Study Team, based of PPUC data

8-1-1-5 Provision for uncollectible revenue

The provision for uncollectible allowances accounts for approximately 1% of sales (Table 8-1-1-5.1).

Table 8-1-1-5.1 Provision for uncollectible revenue

	FY2014	*FY2015*	*FY2016*
Provision for non-collectible bills (US$)	299,182	722,094	740,783
Ratio for non-collectible bills	0.4%	1.1%	1.0%

Source: Study Team, based of PPUC data

8-1-1-6 Power Losses

The loss rate stands at around 17%. The technical loss rate and nontechnical loss rate stand at about 9% and 8%, respectively (Table 8-1-1-6.1).

Table 8-1-1-6.1 Power loss

	FY2012	*FY2013*	*FY2014*	*FY2015*	*FY2016*
Loss (kWh)	12,995,914	13,692,654	12,478,716	16,186,643	14,788,677
Loss ratio	17%	17%	16%	19%	17%

Source: PPUC Financial Statements 2016

8-1-2 Financial condition of PPUC's power business

8-1-2-1 Balance Sheet

Table 8-1-2-1.1 below shows the balance sheet for PPUC's power business.

Table 8-1-2-1.1 PPUC EPO Balance Sheet（US$）

	FY2012	FY2013	FY2014	FY2015	FY2016
Assets					
Utility plant					
Depreciable utility plant	24,423,327	26,720,881	39,675,708	36,692,760	34,936,922
Non-depreciable utility plant	2,196,741	2,166,962	181,900	132,083	945,015
Net utility plant	26,620,068	28,887,843	39,857,608	36,824,843	35,881,937
Current assets					
Cash and cash equivalents	3,827,394	3,899,227	7,189,860	5,181,027	10,506,408
Receivables					
Trade	2,836,726	3,075,789	2,864,924	2,657,017	2,965,609
Affiliate	1,311,610	1,746,983	2,178,969	3,323,187	3,328,056
Contracts	102,780	121,241	92,672	102,469	102,951
Other	31,686	63,757	93,657	406,446	21,233
	4,282,802	5,007,770	5,230,222	6,489,119	6,417,849
Less allowance for doubtful accounts	(410,000)	(471,000)	(626,000)	(617,430)	(740,784)
Net receivables	3,872,802	4,536,770	4,604,222	5,871,689	5,677,065
Prepaid expenses	290,098	262,986	124,134	164,461	180,581
Inventory, net	8,691,303	8,234,994	8,380,427	7,820,744	7,274,143
Due from grantor agency		83,071	118,000		
Total current assets	16,681,597	17,017,048	20,416,643	19,037,921	23,638,197
Other non-current assets					
Contract receivables	228,260	271,092	203,036	263,442	194,865
TOTAL assets	43,529,925	46,175,983	60,477,287	56,126,206	59,714,999
Deferred outflows of pension resources				591,134	842,875
Total	43,529,925	46,175,983	60,477,287	56,717,340	60,557,874
LIABILITIES AND CAPITAL					
Net position					
Net investment in utility plant	20,996,199	23,617,298	34,916,479	32,223,800	31,631,972
Unrestricted	6,953,195	7,761,110	10,593,960	3,742,340	7,739,892
Total net position	27,949,394	31,378,408	45,510,439	35,966,140	39,371,864
Commitment and contingencies					
Current liabilities					
Current position of long-term debt	527,601	537,508	548,183	559,186	572,043
Accounts payable	6,168,973	5,906,378	6,565,240	3,544,462	3,928,892
Accrued expenses	348,845	362,122	386,584	396,346	374,520
Grant advances from the Republic of Palau				500,000	560,059
Customer deposits	456,665	450,529	473,895	728,334	861,053
Total current liabilities	7,502,084	7,256,537	7,973,902	5,728,328	6,296,567
Long-term debt, net of current portion	8,078,447	7,541,038	6,992,946	6,433,860	5,861,922
Net pension liability				7,711,821	7,915,040
Total liabilities	15,580,531	14,797,575	14,966,848	19,874,009	20,073,529
Deferred inflows of pension resources				877,191	1,112,481
TOTAL	43,529,925	46,175,983	60,477,287	56,717,340	60,557,874

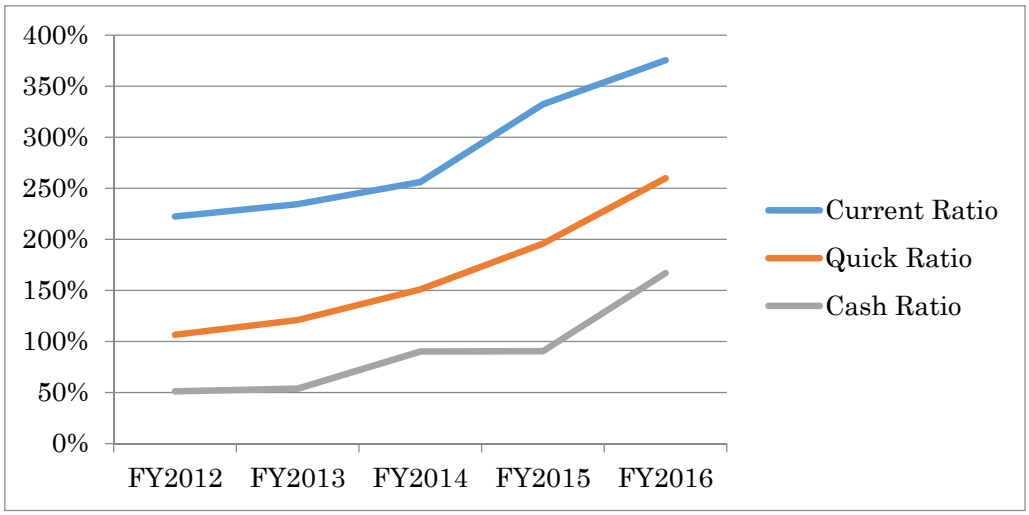
Source: PPUC Financial Statements 2016, 2015, 2014, 2013

The current ratio, quick ratio, and cash ratio improved up to 2016. Each indicator shows sufficient repayment ability and cash-out capacity for short-term debt (Table 8-1-2-1.2, Figure 8-1-2-1.1).

Table 8-1-2-1.2 Liquidity indicators

Current Ratio	222%	235%	256%	332%	375%
Quick Ratio	107%	121%	151%	196%	260%
Cash Ratio	51%	54%	90%	90%	167%
Capital-to-Assets Ratio	64%	68%	75%	63%	65%
Working Capital	9,179,513	9,760,511	12,442,741	13,309,593	17,341,630

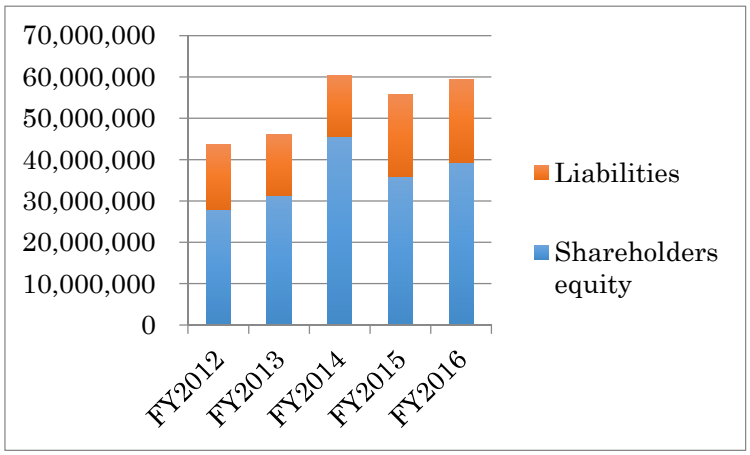
Source: Study Team



Source： Study Team

Figure 8-1-2-1.1 Current, quick, and cash ratios

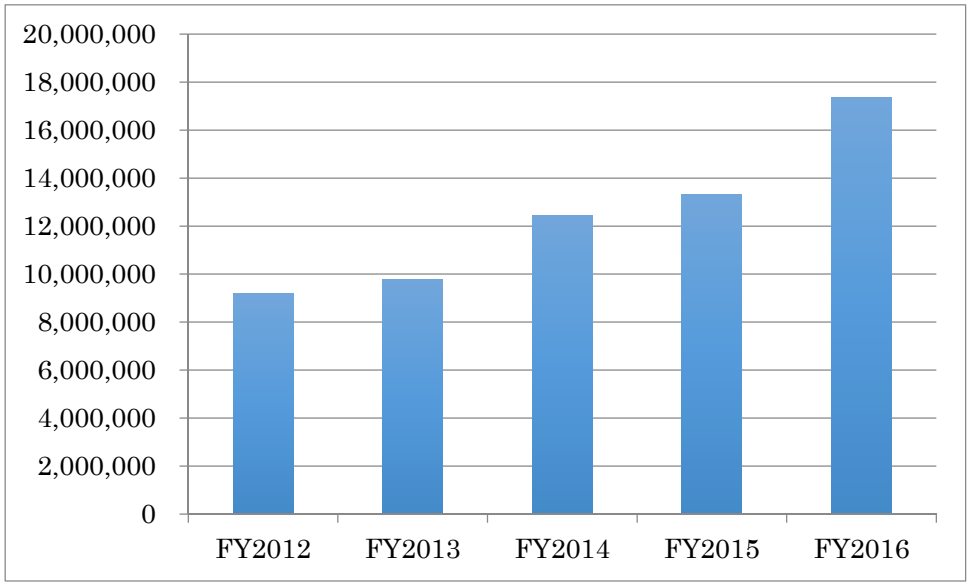
The capital ratio has remained at the 65% level for the past five years. The borrowing ratio cost remains stable because the large capital investment funds are grants from donors such as the Japanese government rather than being borrowed.



Source: Study Team

Figure 8-1-2-1.2　Capital and borrowings（US$）

Working capital was about 17 million dollars in 2016, assuring sufficient short-term funds to carry out daily business (Figure 8-1-2-1.3).



Source: Study Team

Figure 8-1-2-1.3 Working capital（US$）

8-1-2-2 Income Statement

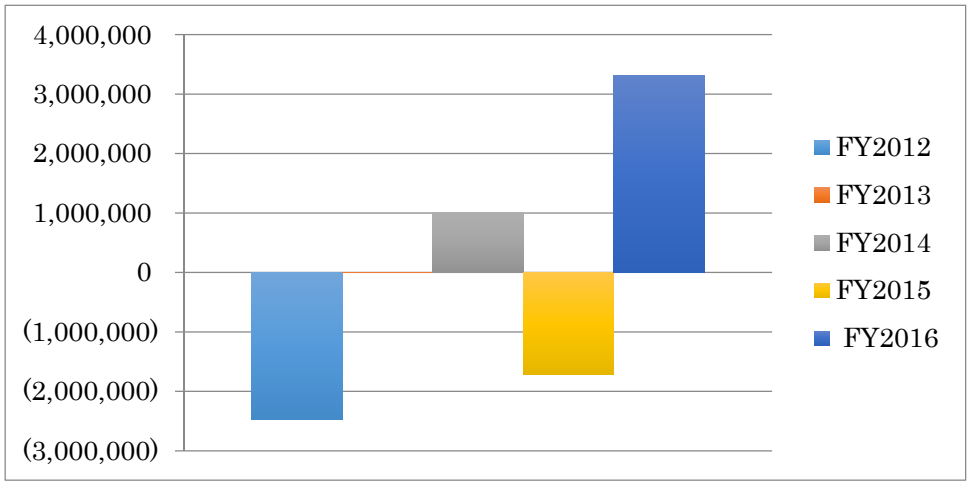
Table 8-1-2-2.1 below shows the income statement for PPUC's electric power operations.

Table 8-1-2-2.1 PPUC EPO Income Statement（US$）

	FY2012	FY2013	FY2014	FY2015	FY2016
Operating revenue					
Power	25,237,736	26,360,007	27,308,961	21,057,044	19,806,787
Other	609,155	642,914	634,458	772,035	907,576
Total operating revenue	25,846,891	27,002,921	27,943,419	21,829,079	20,714,363
Provision for uncollectible receivables	(208,071)	(60,353)	(291,855)		(73,488)
Net operating revenue	25,638,820	26,942,568	27,651,564	21,829,079	20,640,875
Operating expense					
Fuel generation	18,973,663	18,828,586	18,732,306	14,555,200	10,134,675
Depreciation	1,757,965	1,802,616	2,187,173	2,615,286	2,671,939
Generation other cost	3,083,178	2,949,702	3,503,046	3,830,008	2,435,693
Administration	1,153,797	1,094,458	920,174	856,819	972,775
Distribution and transmission	922,759	723,423	813,236	935,307	1,250,986
Renewable energy	99,934	106,151	554,192	496,443	537,807
Engineering services	200,365	314,561	92,185	97,713	334,794
Total operating expenses	26,191,661	25,819,497	26,802,312	23,386,776	18,338,669
Operating income	(552,841)	1,123,071	849,252	(1,557,697)	2,302,206
No operating revenue					
Operating subsidies from the Republic of Palau			100,729		496,000
Inventory obsolescence recovery			266,203	181,459	
Grants		345,258	45,000	102,892	611,958
Gain/Loss on disposal of utility plant	(218,055)	250		(95,584)	
Interest income	2,358	538	1,237	4,219	3,217
Interest expense	(480,755)	(404,185)	(383,207)	(355,523)	(327,972)
Others	(20,972)	1,440	121,609		228,563
Write-downs for generators, parts, and inventories		(1,070,000)			
Loss of disposal of assets by a catastrophic fire	(1,208,189)				
Total non-operating revenues, net	(1,925,613)	(1,126,699)	151,571	(162,537)	1,011,766
income before capital contributions	(2,478,454)	(3,628)	1,000,823	(1,720,234)	3,313,972

Source: PPUC Financial Statements 2016, 2015, 2014, 2013

Although the amount of power generation since 2012 has been increasing, electricity sales revenue has been declining due to an electricity tariff reduction to adjust for the fuel costs declines seen since 2015. The operating loss has been recorded at 1.5 million dollars, mostly as a consequence of repair facility renovation costs. In 2016, however, a profit of 2.3 million dollars was recorded thanks to reduced operating expenses (Table 8-1-2-2.1). The operating profit margin and ordinary income margin improved significantly in 2016 compared to the 2015 levels (Figure 8-1-2-2.1).



Source: Study Team

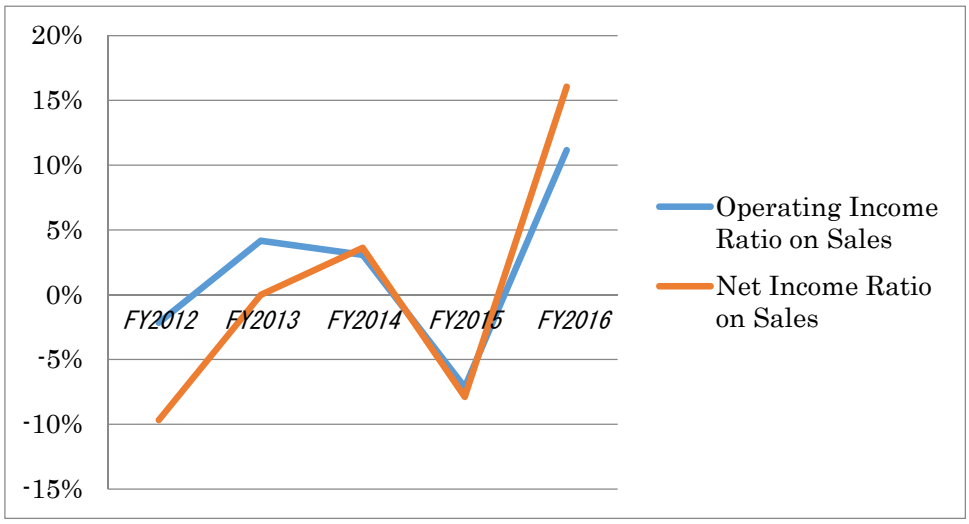
Figure 8-1-2-2.1　Net Income for the EPO（US$）

Electric power sales are declining, but further declines in expense ratios pushed up both the operating margin and ordinary income by significant levels in 2016 compared to the previous year (Table 8-1-2-2.2, Figure 8-1-2-2.2).

Table 8-1-2-2.2　Major profit indicators

	FY2012	*FY2013*	*FY2014*	*FY2015*	*FY2016*
Operating Income Ratio on Sales	-2%	4%	3%	-7%	11%
Net Income Ratio on Sales	-10%	0%	4%	-8%	16%
Operating expense/Operating revenue	102%	96%	97%	107%	89%

Source: Study Team



Source: Study Team

Figure 8-1-2-2.2 Operating and net income ratios (%)

8-1-3 Long-term debts

The balances of long-term debts are listed in Table 8-1-3.1.

Table 8-1-3.1 Long-term borrowing of PPUC (US$)

Type	Amount ($)	Rate ($, %)	Fixed/Float	Lender
Bank loans (ROP guaranteed)	4,200,000	3.00%	Fixed	Taiwanese Bank
Bank loans	2,233,965	7.50%	Fixed	National Development Bank of Palau
Concessional loans	923,331	LIBOR + 0.6%	Float	ADB
Special Drawing Rights	986,898	1.00%	Fixed	IMF
Total long-term debt	8,344,194			
Current maturities	(572,043)			
Balance at the end of FY2016	7,772,151			
of which, EPO	5,861,922			
of which, WWO	1,910,229			

Source: Study Team, based on PPUC Financial Statements 2016

The long-term debt outstanding in 2016 was approximately 7.8 million US dollars, of which 5.9 million USD was for the electricity business. Bank loans were used for investing in new power-generation facilities and renovating existing facilities.

The borrowings from ADB and IMF are soft loans to set up and renew sewage facilities in Koror State and Airai Province. ADB has provided credit facilities totaling US $ 26.9 million.

The borrowing interest rate for general capital investment funds in PPUC is expected to reach 7.5% (the interest rate for personal loans in Palau stands at around 15%).

8-1-4 Capital Contributions to EPO

International donor agencies fund the implementation of capital investments that require large funding for PPUC. Funds were received from the Japanese government through the Palauan government each year from 2012 to 2014. In 2015 and 2016 there were no grants to electric power projects from other governments (Table 8-1-4.1).

Table 8-1-4.1 Capital contributions to EPO (US$)

	FY2012	*FY2013*	*FY2014*	*FY2015*	*FY2016*
Capital contribution					
Capital contribution from the Republic of Palau					91,752
Grants from the Japan Government	2,109,104	3,432,642	13,131,208		

Source：Study Team, based on PPUC Financial Statements 2016, 2015, 2014, 2013

8-1-5 Subsidies from the Government

PPUC obtains subsidies from the government by following a procedure to request the necessary amounts. The subsidy amounts are shown in Table 8-1-5.1 below.

- The subsidies for EPO are provided not as compensation for electricity revenue, but as part of a government welfare policy to pay electricity fees for low-income earners.
- WWO received government subsidies to cover for project deficits of 3.7 million dollars in 2015 and 3.1 million dollars in 2016. Water and sewage projects are also expected to depend on government subsidies in the future.

Table 8-1-5.1 Subsidies from the government (US$)

	FY2012	*FY2013*	*FY2014*	*FY2015*	*FY2016*
EPO	0	0	100,729	0	496,000
WWO	0	2,672,734	1,700,000	3,419,045	2,266,993
Total	0	2,672,734	1,800,729	3,419,045	2,762,993

Source: Study Team, based on PPUC Financial Statements

8-1-6 Business Separations between EPO and WWO

The Palau government regulations require that PPUC's EPO and WWO be separately financed and managed, hence there is no financial intermediation or cross subsidies between them (hence, an increase in electricity fee could not be used to compensate for a deficit of WWO funds).

8-1-7 Suggestion from a Financial Analysis Standpoint

The retained earnings on the balance sheets of the PPUC EPO were as small as US $ 7 million in 2016, leaving PPUC without enough of its own capital to make large future capital investments. Though set based on the fuel cost (Fuel) and business operation cost (Energy), the electricity tariff is not at a level sufficient to build up enough profit. It will be important to accumulate the profits necessary for capital investment through electric power sales income and to add expenses for the expected capital expenditure by raising the tariff as a medium- to long-term strategy for business. In this way, PPUC will not have to rely on government subsidies or financial assistance from international donor agencies.

8-2 Economic Analysis

8-2-1 Purpose of Economic Analysis

Improvement of the power generation system and transmission/distribution system through multiple scenarios will be considered in this project. In one of the scenarios considered, renewable energy (RE) is introduced up to a ratio of 45%. In this economic analysis we calculated the financial internal rate of return (FIRR) by expense and income and the 2) the economic internal rate of return (EIRR) by cost and benefit at the national level, assuming the implementation of a 45% RE introduction ratio project. We also set up multiple electricity fee scenarios and carried out an economic sensitivity analysis.

8-2-2 FIRR

The FIRR is calculated by expanding the expenditure and income generated in accordance with the 45% ratio RE in the plan and transmission and distribution plan for each year from 2018 to 2025 (Table 8-2-2-1.1).

8-2-2-1 Expense

Capital Expenditure for RE: Total US$ 112,305,000（PV, $66,000,000; Battery, $39,515,000; Transmission line to RE, $180,000; Inverter, $4,020,000, RE management system, $2,590,000）

Capital Expenditure for Distribution: Total US$ 35,000,000

PV Operational & Maintenance: 2% of PV System Expenditure（Standard Cost Ratio[1] for the PV project）

Battery Operational & Maintenance: 2% of Battery Expenditure (Standard Cost Ratio for the PV project)

DEG generation cost：US$0.177/kWh（Calculated based on PPUC financial statements）

O&M cost for DEG：US$0.05/kWh（Calculated based on PPUC financial statements）

O&M cost for Distribution：US$0.03/kWh（Calculated based on PPUC financial statements）

Table 8-1-2-2.1 Capital investment for the Master Plan (US$)

Capital Expenditure			
Year	PV Generation	Trans./Sub Station	Annual Capital Expenditure
2018	9,332,879	1,810,000	11,142,879
2019	8,315,098	10,498,000	18,813,098
2020	10,646,428	5,792,000	16,438,428
2021	285,000	1,140,000	1,425,000
2022	10,445,701	6,612,000	17,057,701
2023	27,233,399	3,648,000	30,881,399
2024	25,941,098	1,705,000	27,646,098
2025	20,105,397	3,795,000	23,900,397
Sub Total	112,305,000	35,000,000	
Total Capital Cost			147,305,000

Source: Study Team

8-2-2-2 Income

RE Sales Income: Income in line with the RE45% case from 2018 to 2025

Electricity Supply（kWh) x Tariff ($/kWh)

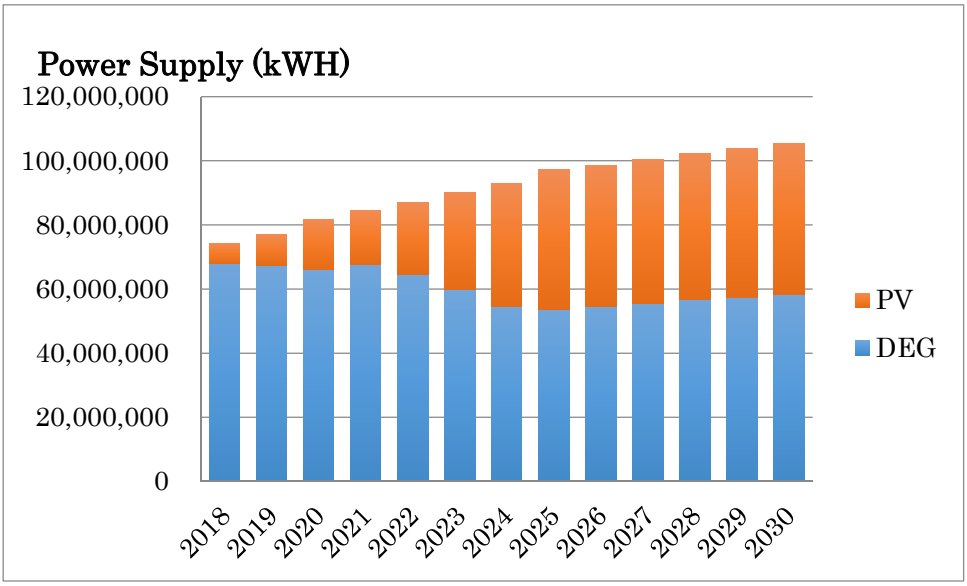
Power revenue increase from the distribution system renewal:

Currently not available, under study by the Project Team

Power supply increase (kWh) x Tariff ($/kWh)

Salvage value： The salvage value of the PV system in 2025 is realized as FIRR income, based on a 17-year statutory useful life of PV and 40-year statutory useful life of the distribution system.

[1] "Cost-effective system stabilization measures accompanying the introduction of renewable energy in the micro grid," Institute of Electrical Engineers (Mr. Tadayuki Ogawa).



Source: Study Team

Figure 8-2-2-2.1 Power supply volume by PPUC

Table 8-2-2-2.2 Cash flow for FIRR (in case of a $0.30/kWh tariff)

Year	Expenditure for PV, Distribution and Sub Station	Fuel Cost for DEG Generation	Operation and Maintenance Cost for PV and DEG	Income from Electricity Sales	Net Income with Salvage Value
2018	11,142,879	12,014,913	5,808,738	22,280,371	(6,686,159)
2019	18,813,098	11,915,018	6,057,637	23,106,344	(13,679,409)
2020	16,438,428	11,718,535	6,412,021	24,520,893	(10,048,090)
2021	1,425,000	12,001,788	6,502,042	25,364,107	5,435,277
2022	17,057,701	11,419,469	6,779,529	26,049,842	(9,206,858)
2023	30,881,399	10,602,094	7,425,486	27,062,727	(21,846,252)
2024	27,646,098	9,629,489	8,023,218	27,851,824	(17,446,981)
2025	23,900,397	9,505,954	8,553,667	29,135,238	106,999,382
Total	147,305,000	88,807,260	55,562,337	205,371,345	
				FIRR=	11.0%

Source: Study Team

8-2-3 EIRR

The EIRR is calculated by expanding the Cost and Benefit generated in accordance with the RE 45% target set in the plan and transmission and distribution plan each year from 2018 to 2025.

8-2-3-1 Cost

The cost for the EIRR is the same as the FIRR expense, excluding an operational and maintenance cost adjusted by a Standard Conversion Factor[2] of 0.9.

[2] The standard conversion factor of 0.9 is set by the Asian Development Bank for development projects in Pacific countries.

8-2-3-2 Benefit

Power supply increase in Palau:

Pure power increase in Palau by RE based on power demand up to the year 2025. Increase of supply (kWh) x Tariff（$/kWh)（Figure 8-2-3-2.1)

Cost reduction of DEG: Reduction of the DEG fuel cost by RE is realized as EIRR benefit

(Fuel cost $0.177/kWh x PV supply)

Power supply increase by renewal of the distribution system:

Improved supply ratio 0.12%[3] x supply volume (kWh) on the existing distribution area

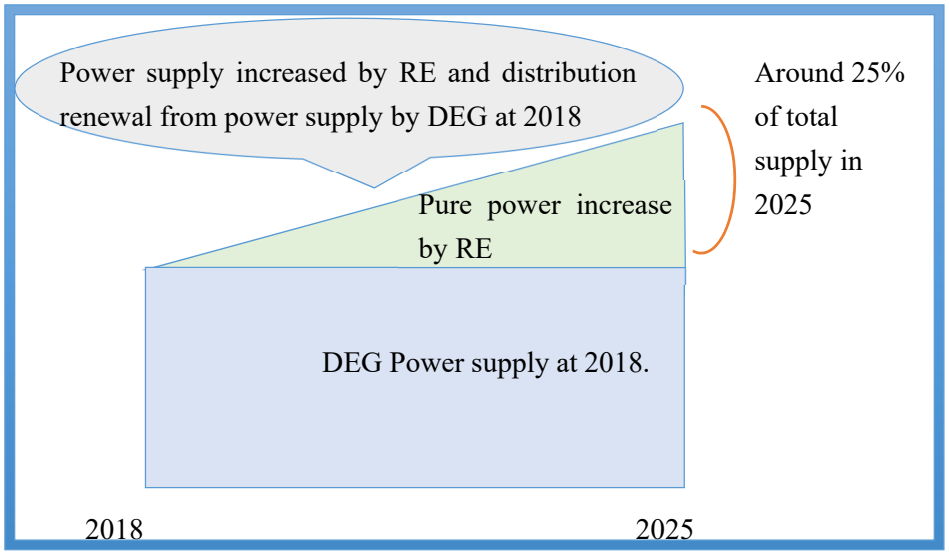
Benefits realized by a stabilized distribution system:

Improved Consumer Income[4] US$211,225 realized by stabilized distribution annually)

CO2 Reduction Value: The volume of CO2 emission reduced by RE is valued at US$19/ton as an Economic benefit[5].

Salvage value: Salvage value of the PV system at 2025 is realized as EIRR benefit, based on a statutory useful life of PV of 17 years and statutory useful life of the distribution system of 40 years.

[3] The loss from power blackouts is 86,242 kWh, or 0.12% of the total power supply in the year 2017.
[4] Per Capita Income US$7,280 x Improved ratio 1.2% x Population 2,414 in the targeted area.
[5] The price per ton of CO2 is based on the European market transaction price as of May 2018. The seller of the CO2 reduction rights needs to bear the transaction cost in actual sales transactions, so this economic benefit represents only the calculation value.



Source: Study Team

Figure 8-2-3-2.1 EIRR Benefit by electricity supply

Table 8-2-3-2.1 Cash flow for EIRR (in case of a $0.30/kWh tariff)

Year	Expenditure for PV, Distribution and Sub Station	O$M Cost adjusted by SCF(0.9)	Benefit from Increased Power Supply	Benefit from Fuel Cost Saved	Benefit from CO2 Reduction	Benefit from Distribution Renovation	Net Benefit with Salvage Value
2018	5,310,155	340,442	541,999	1,130,506	127,089	299,617	(9,384,110)
2019	6,305,443	579,690	1,367,973	1,717,726	186,200	302,894	(15,817,995)
2020	8,053,013	928,607	2,782,521	2,748,792	280,778	308,506	(11,246,437)
2021	8,416,136	966,418	3,625,735	2,963,035	292,600	311,851	4,801,804
2022	10,088,853	1,304,985	4,311,471	3,949,938	379,789	314,572	(9,406,917)
2023	12,487,119	2,011,030	5,324,355	5,364,915	496,533	318,590	(21,388,036)
2024	14,924,698	2,697,352	6,113,452	6,803,086	611,800	321,721	(16,493,390)
2025	16,417,494	3,193,601	7,396,866	7,683,836	665,000	326,812	108,802,679
Total	82,002,911	12,022,123	31,464,373	32,361,834	3,039,789	2,504,564	
						EIRR=	8.8%

Source: Study Team

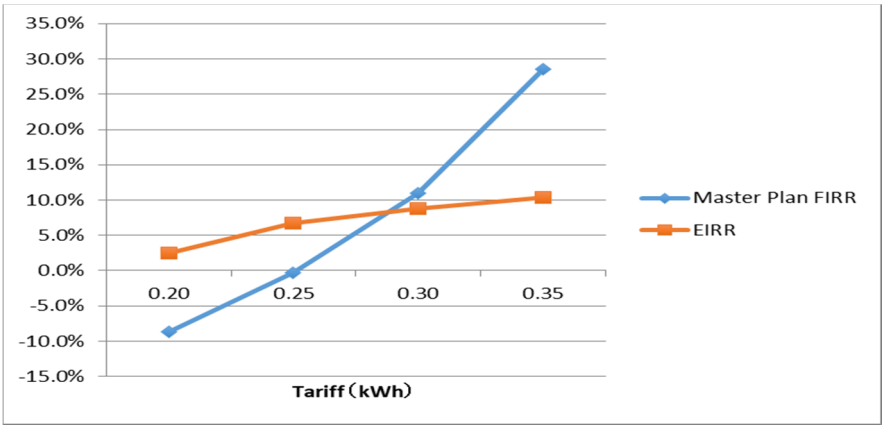
8-2-4 Calculation results for the FIRR, EIRR, and sensitivity analysis with tariff changes

The calculation results for the FIRR and EIRR for each RE power charge setting are shown in the following table and figure. The FIRR exceeds the EIRR at all prices because only the pure increase in electricity supply in Palau by RE is included as a benefit in the EIRR, while all of the RE supply is included as revenue.

Table 8-2-4.1 Sensitivity of FIRR and EIRR to tariff changes

Tariff	Tariff ($/kWh)			
	0.20	0.25	0.30	0.35
Master Plan FIRR	-8.7%	-0.3%	11.0%	28.6%
EIRR	2.5%	6.7%	8.8%	10.4%

Source: Study Team



Source: Study Team

Figure 8-2-4.1 FIRR and EIRR with each tariff

8-2-5 Other Notes

- The DEG power development is not included in this survey. Therefore, the calculation does not factor in the increase in the fuel cost burden attributable to the decrease in DEG fuel efficiency caused by the introduction of RE, or the increase in other expenses.
- Regardless of the introduction of RE, maintenance and management costs are not reduced.
- In calculating the price escalation, the long-term inflation rate is difficult to predict. If the costs and benefits of this project increase, the inflation related to the costs and benefits will be offset. The inflation rate is therefore disregarded in the calculation for each item.

8-2-6 Reference Electricity Price Calculated by the Conversion Tool to Economic Prices

The following is given with reference to the electricity price calculated as a Long run marginal cost (LRMC).

8-2-6-1 Long run marginal cost (LRMC)

In the project analysis, the long-term marginal cost of the assumed investment project is calculated and the sum of the annual maintenance cost is considered the "marginal cost based on the project implementation (construction / maintenance operation)." The marginal cost is defined as the “calculated price at the currency term of the project's economic benefit” as “service price (marginal cost price)” of the service. The capital recovery factor (CRF) is applied to estimate the LRMC and is expressed by the following equation.

LRMC ＝ Project Expenditure × CRF ＋annual Operational Maintenance Cost

Formula defining CRF: $\text{CRF} \equiv \frac{i(1+i)^n}{(1+i)^n-1}$

(i, discount rate； n, number of years of the project)

Reference LRMC calculated by PV expenditure: US$0.287/kWh

Reference LRMC calculated by Distribution: US$0.051/kWh

8-2-7 Consideration of RE Based on the Results of the Economic Analysis

1) In order to achieve the social discount rate of 9%[6] for development projects, it will be necessary to set an electricity fee of US $ 0.30 / kWh for the EIRR. This price is equivalent to the current average tariff by DEG. On the other hand, the electricity price by DEG fluctuates greatly according to the diesel fuel cost. For example, the DEG electricity price was over US $ 0.40 / kWh for the period from 2012 to 2014, which was quite high from the calculated PV cost. While PV cannot always be assumed to be high or low compared with DEG, the PV cost is stable.

2) Incorporating PV in Palau can be expected to generate a stable power generation cost in the power supply system in Palau, reduce the power cost fluctuation for PPUC, and enable the supply electricity at a stable price. Apart from DEG power dependence on imported resources, ownership of the PV power generation business will allow PPUC to choose the optimum power mix for energy. It will therefore be economically reasonable for PPUC to enter into PV business operation.

8-3 Financing Plan

8-3-1 Financing by borrowing or grant

This project can only be implemented if there is a realistic and economic financing plan. If PPUC cannot finance the capital expenditure of RE with its own funds, it will be necessary to obtain funds from outside by borrowing or grants.

8-3-2 Candidate financing sources

The main candidate entities for grants / borrowing are shown below.

(1) International Development Assistance Organization
Asian Development Bank, JICA, other international development aid organizations, etc.
With this financing source, the preferred means for repayment would be loans granted or concessional term loans and borrowings with little interest burden.

(2) Multilateral Fund for Climate Change Mitigation
The Green Climate Fund (GCF) or a similar fund established to support greenhouse gas reduction (mitigation) and cope with the effects of climate change (adaptation).
With this funding source, the preferred means for repayment would be loans granted or concessional terms loans and borrowings with little interest burden.

(3) Private loan
Private bank loans, investments from private investment funds, etc.
Repayment and interest cost would be set in accordance with the private financial markets.

(4) Investment by an Independent Power Producer loan
RE investment by an IPP does not require any financial expenditure by PPUC.

8-3-3 Financing Schedule for the Master Plan

[6] SDR is set at 9.0%, the level used by ADB for most Pacific countries.

Financing schedules for three different cases are set up for PV investment, based on borrowing ratios. The borrowing condition is set up to 2030, five years beyond the Master Plan. The interest rate for a borrowing term of 13 years (grace period of 8 years) is assumed to be that for a concessional term loan at a preferential interest rate of 3.0%.

As shown in Table 8-3-3.2, external borrowing is still required in 2030 in the case with the Debt ratio set at 80%.

(1) Debt Ratio 30%

Table 8-3-3.1 Funding status with a tariff of $ 0.30 kWh, borrowing ratio of 30%, and borrowing rate of 3.0%

Financing Projection for Master Plan											
Year		Out Flow (US$, million)				In Flow (US$, million)					Net Cash (USD, million)
		Expenditure and O&M Cost	Loan		Total Out Flow	Electric Power Revenue	Finance			Total Inflow	
			Repayment	Interest			Equity	Debt	Total		
1	2018	28,966,529	0	60,722	29,027,251	22,280,371	4,722,816	2,024,064	6,746,881	29,027,251	0
2	2019	36,785,753	0	185,506	36,971,259	23,106,344	9,705,440	4,159,474	13,864,915	36,971,259	0
3	2020	34,568,983	0	278,445	34,847,428	24,520,893	7,228,575	3,097,961	10,326,535	34,847,428	0
4	2021	19,928,830	0	278,445	20,207,275	25,364,107	0	0	0	25,364,107	5,156,832
5	2022	35,256,700	0	364,588	35,621,288	26,049,842	6,700,012	2,871,434	9,571,446	35,621,288	0
6	2023	48,908,979	0	566,301	49,475,280	27,062,727	15,688,787	6,723,766	22,412,553	49,475,280	0
7	2024	45,298,805	0	729,893	46,028,698	27,851,824	12,723,812	5,453,062	18,176,874	46,028,698	0
8	2025	41,960,017	0	852,993	42,813,010	29,135,238	9,574,441	4,103,332	13,677,773	42,813,010	0
9	2026	18,247,869	5,686,619	682,394	24,616,882	29,576,856	0	0	0	29,576,856	4,959,973
10	2027	18,495,361	5,686,619	511,796	24,693,775	30,157,454	0	0	0	30,157,454	5,463,679
11	2028	18,725,179	5,686,619	341,197	24,752,995	30,696,591	0	0	0	30,696,591	5,943,597
12	2029	18,936,086	5,686,619	170,599	24,793,303	31,191,365	0	0	0	31,191,365	6,398,061
13	2030	19,122,643	5,686,619	-0	24,809,262	31,629,015	0	0	0	31,629,015	6,819,753

(2) Debt Ratio 80%

Table 8-3-3.2 Funding status with a tariff of $ 0.30 kWh, borrowing ratio of 80%, and borrowing rate of 3.0%

Financing Projection for Master Plan											
Year		Out Flow (US$, million)				In Flow (US$, million)					Net Cash (USD, million)
		Expenditure and O&M Cost	Loan		Total Out Flow	Electric Power Revenue	Finance			Total Inflow	
			Repayment	Interest			Equity	Debt	Total		
1	2018	28,966,529	0	164,414	29,130,943	22,280,371	1,370,114	5,480,458	6,850,572	29,130,943	0
2	2019	36,785,753	0	504,836	37,290,589	23,106,344	2,836,849	11,347,395	14,184,244	37,290,589	0
3	2020	34,568,983	0	764,334	35,333,317	24,520,893	2,162,485	8,649,939	10,812,424	35,333,317	0
4	2021	19,928,830	0	764,334	20,693,164	25,364,107	0	0	0	25,364,107	4,670,943
5	2022	35,256,700	0	1,009,527	36,266,227	26,049,842	2,043,277	8,173,108	10,216,385	36,266,227	0
6	2023	48,908,979	0	1,571,554	50,480,533	27,062,727	4,683,561	18,734,245	23,417,807	50,480,533	0
7	2024	45,298,805	0	2,039,223	47,338,028	27,851,824	3,897,241	15,588,964	19,486,204	47,338,028	0
8	2025	41,960,017	0	2,404,732	44,364,749	29,135,238	3,045,902	12,183,609	15,229,511	44,364,749	0
9	2026	18,247,869	16,031,544	2,086,728	36,366,141	29,576,856	1,357,857	5,431,428	6,789,285	36,366,141	0
10	2027	18,495,361	16,031,544	1,752,714	36,279,618	30,157,454	1,224,433	4,897,732	6,122,165	36,279,618	0
11	2028	18,725,179	16,031,544	1,402,880	36,159,602	30,696,591	1,092,602	4,370,409	5,463,011	36,159,602	0
12	2029	18,936,086	16,031,544	1,037,463	36,005,093	31,191,365	962,746	3,850,982	4,813,728	36,005,093	0
13	2030	19,122,643	16,031,544	656,886	35,811,073	31,629,015	836,412	3,345,646	4,182,058	35,811,073	0

(3) Debt Ratio 50%

Table 8-3-3.3 Funding status with a tariff of $ 0.30 kWh, borrowing ratio of 50%, and borrowing rate of 3.0%

Financing Projection for Master Plan											
Year		Out Flow (US$, million)				In Flow (US$, million)					Net Cash (USD, million)
		Expenditure and O&M Cost	Loan		Total Out Flow	Electric Power Revenue	Finance			Total Inflow	
			Repayment	Interest			Equity	Debt	Total		
1	2018	28,966,529	0	101,820	29,068,349	22,280,371	3,393,989	3,393,989	6,787,978	29,068,349	0
2	2019	36,785,753	0	311,686	37,097,439	23,106,344	6,995,547	6,995,547	13,991,095	37,097,439	0
3	2020	34,568,983	0	469,449	35,038,433	24,520,893	5,258,770	5,258,770	10,517,540	35,038,433	0
4	2021	19,928,830	0	469,449	20,398,279	25,364,107	0	0	0	25,364,107	4,965,828
5	2022	35,256,700	0	616,804	35,873,504	26,049,842	4,911,831	4,911,831	9,823,662	35,873,504	0
6	2023	48,908,979	0	958,881	49,867,860	27,062,727	11,402,567	11,402,567	22,805,134	49,867,860	0
7	2024	45,298,805	0	1,239,173	46,537,978	27,851,824	9,343,077	9,343,077	18,686,155	46,537,978	0
8	2025	41,960,017	0	1,453,345	43,413,363	29,135,238	7,139,063	7,139,063	14,278,125	43,413,363	0
9	2026	18,247,869	9,688,969	1,162,676	29,099,514	29,576,856	0	0	0	29,576,856	477,341
10	2027	18,495,361	9,688,969	872,007	29,056,337	30,157,454	0	0	0	30,157,454	1,101,117
11	2028	18,725,179	9,688,969	581,338	28,995,486	30,696,591	0	0	0	30,696,591	1,701,105
12	2029	18,936,086	9,688,969	290,669	28,915,724	31,191,365	0	0	0	31,191,365	2,275,641
13	2030	19,122,643	9,688,969	0	28,811,612	31,629,015	0	0	0	31,629,015	2,817,403

(4) Required External Debt

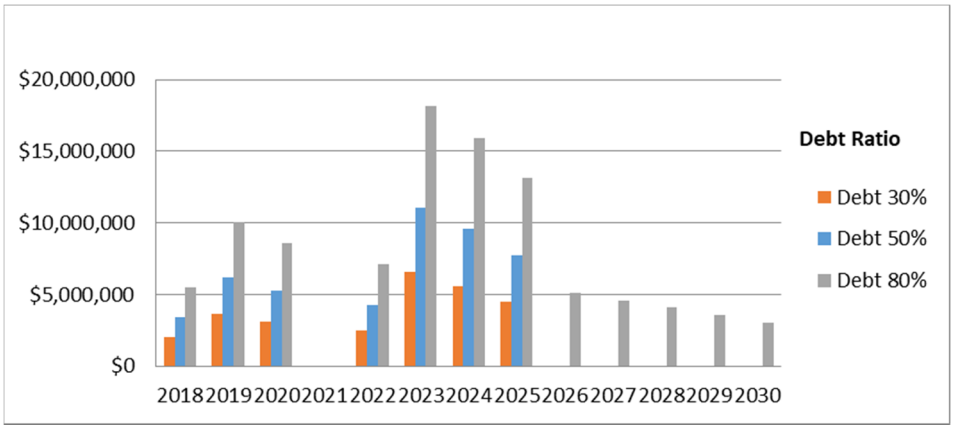


Figure 8-3-3.1 Required external debt

8-3-4 Comparison of Debt Financing Amount under Different Financing Conditions

The figures below show the debt financing amounts in different interest rate[7] and electricity fee scenarios. The electricity tariff is the most sensitive factor for determining the sales income to influence the amount of funds raised

[7] In the loan interest rate scenarios, 3% is the rate set for soft loans from aid agencies (equal to the yield of 10-year US Treasury bonds), 8% is the borrowing interest rate of the Palau government bank, and 13% is the commercial loan rate for non-collateralized business in Palau.

(1) External Debt in each tariff scenario (Debt Ratio 50%, Interest Rate 3.0%)

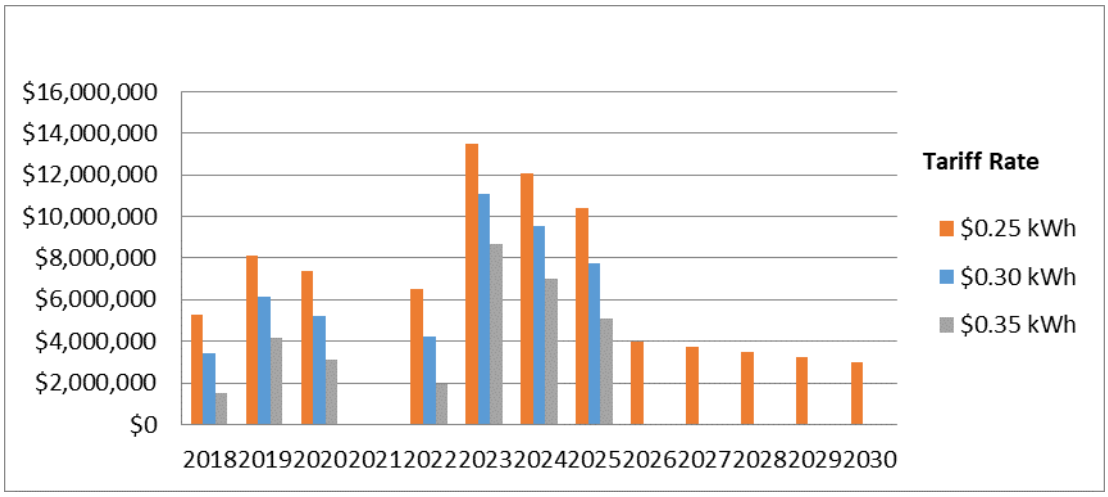


Figure 8-3-4.1 Required external debt in each tariff scenario

The required Debt amount is quite sensitive to the tariff level. Debt is still required in year 2030 when the tariff set at $0.25/kWh.

(2) External debt in each interest rate cost scenario (Tariff $30/kWh, Debt Ratio 50%)

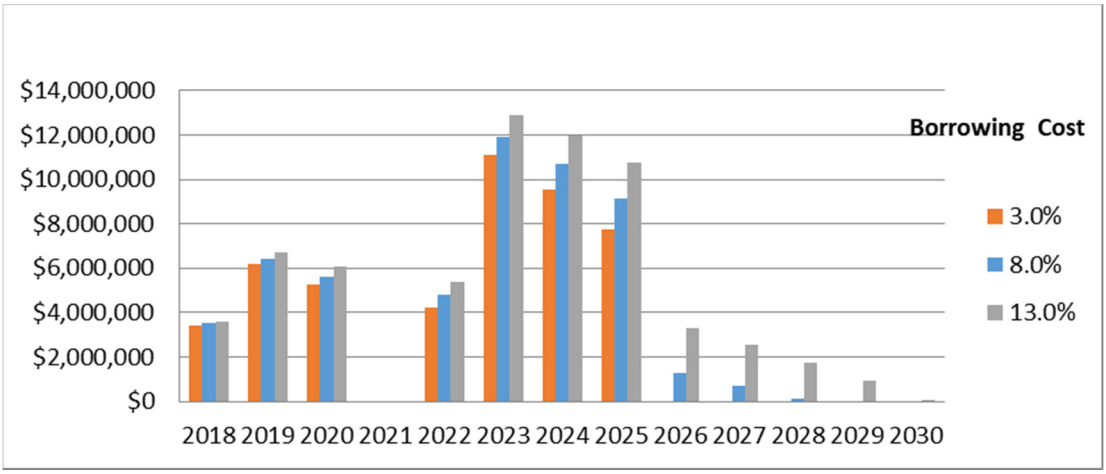


Figure 8-3-4.2 Required external debt in each interest cost scenario

External debt is still required when the interest rate cost is set at 13%.

8-3-5 Review of Financing Schedule

As PV investment will end in 2025, the recommendation is to obtain a positive business cash flow through electricity revenue. To that end, it will be necessary to 1) set the tariff at a level sufficient to cover investment expenditure and 2) rely on investment with its own external funds or through concessional loans.

In the above example, in the unsuitable case where the electricity charge setting is US $ 0.30 kWh and the

borrowing ratio is 0.5, external borrowing will continue even after 2025. It will therefore be desirable to complete financing by 2025 when PV investment is completed. In such a case, a combination of a electricity charge of 0.34 kWh, debt ratio of 30%, and interest rate 3.0% will be required. The desired approach will be to set up an adequate tariff rate and reduce the debt ratio to accumulate positive cash flow.

8-4 Introduction of External Investors as Independent Power Producers (IPPs)

8-4-1 IPP

An IPP is a private enterprise that conducts power generation business to wholesale electricity to electric power companies, not to final customers. IPP investment is generally developed in the power generation sector, as the power transmission/distribution sector needs to supply an equal opportunity for entry by the various power generation companies and a level of openness that assures all customers access to the grid equitably. A business that provides equal service to all stakeholders usually differs in nature from a private company that pursues business profits from investment.

In some countries, the aim of promoting IPP entry is to improve the efficiency of the electric power sector through competition and deregulation. In the case of Palau, the main reason for promoting IPP is to allocate necessary funds for RE investment through the use of private funds. The pursuit of efficiency will be secondary.

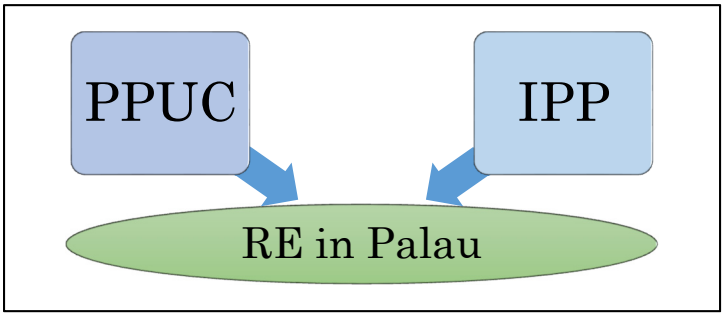
8-4-2 Background Leading up to the Introduction of IPPs into the RE Market

The Palau Energy Road Map aims to generate 45% of the total electricity produced from renewable energy (RE) by 2025. The survey team has determined that the total amount necessary for photovoltaic (PV) investment for RE development is greater than the Palau 2017 national budget. It would therefore be quite difficult to invest the entire investment amount with the PPUC's and the Palau government's own funds.

Lending and grant assistance from international development aid agencies can be considered external sources of funding, but these aid organizations do not necessarily support the electric power sector alone. It may not be easy to raise all of the funds from them. In order to achieve the RE 45% target along the Palau Energy Road Map, IPP will therefore be considered an option (Figure 8-4-2.1)..

Entry into the electric power business by private enterprises not only reduces the burden on the government to raise funds, but also introduces competition in the electricity market.

An incoming IPP would be the first large-scale private power business enterprise in Palau. It thus would be better to consider hiring and using a consulting service for Palau/PPUC for negotiation on setting details such as the IPP project scope, business finance, contract negotiation procedures, etc.



Source: Study Team

Figure 8-4-2.1 IPP entry into the RE market

8-4-3 Role of IPP in Palau

The following figure shows the position of an IPP as an electric wholesaler after the introduction of the IPP system (Fig. 8-4-3.1). The IPP sells PV generated power to PPUC as a wholesaler of electricity. The Palau government may implement support measures to the IPP for business operations based on the contract.

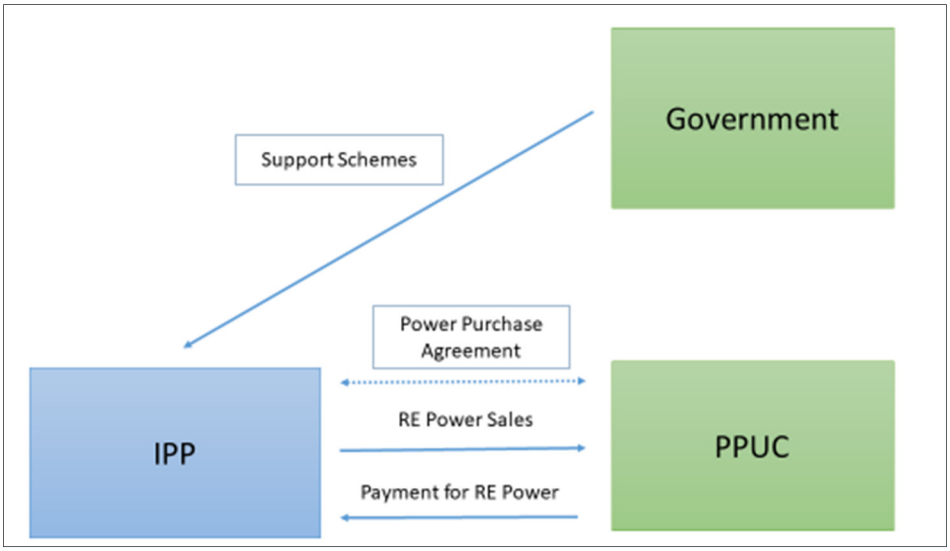


Figure 8-4-3.1 Role of an IPP

8-4-4 PPUC's Power Business Operation after IPP Introduction

The following figure shows the PPUC's power business operation after IPP introduction (Figure 8-4-4.1).

The IPP implements a PV power project and generates power. The IPP supplies the generated power to PPUC's power transmission system. PPUC implements the transmission and distribution project, including consumer services, as before.

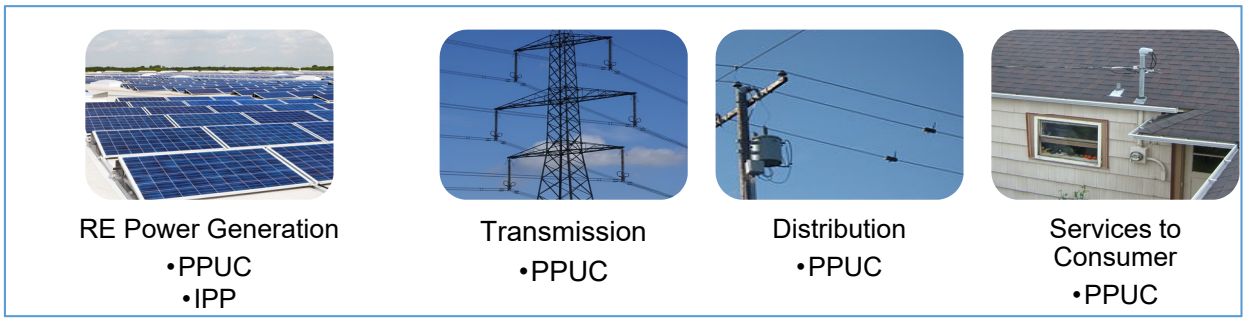
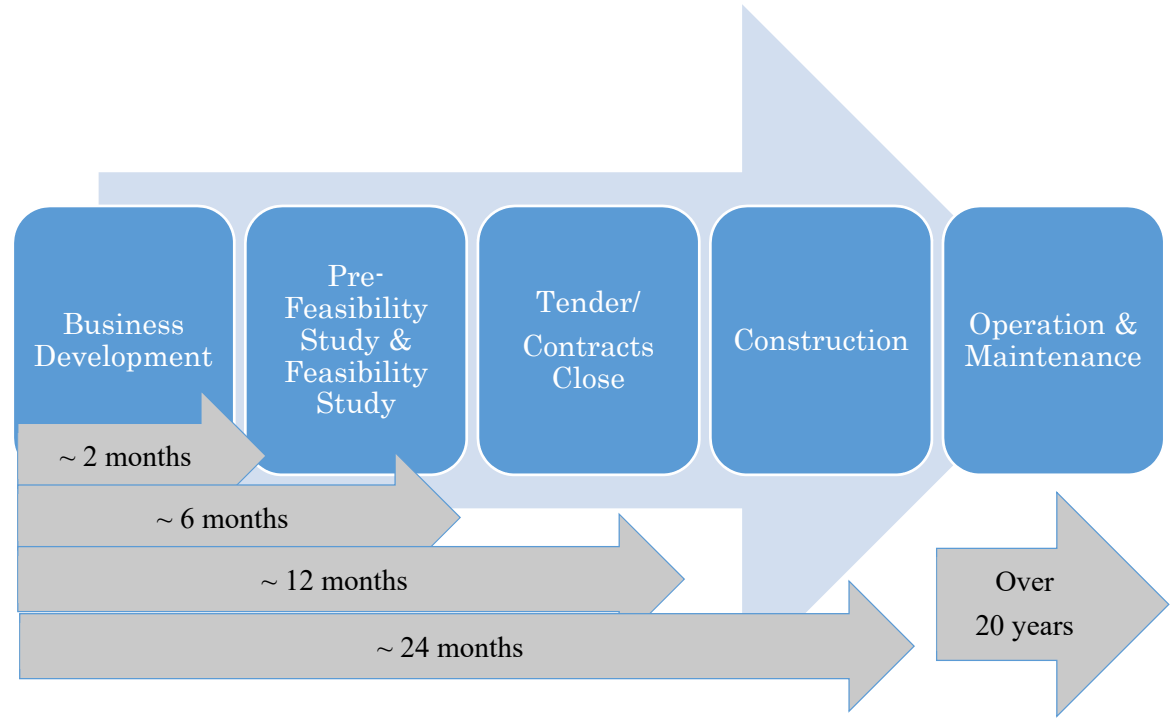


Figure 8-4-4.1 PPUC's power business operation after IPP introduction

8-4-5 Roadmap for PV Investment by IPPs

This section describes the roadmap for project implementation. The IPP will choose a project structure either as a sole entity or project partner. The financing will consist of two parts: an equity investment and project financing to cover the debt portion. The financing of solar PV projects is typically arranged by the developer or sponsor.

The development of a PV project can be broken down into the following phases: business development, pre-feasibility study, feasibility study, contract closing, development and design, construction, and O&M (Figure 8-4-5.1). Each successive phase generally entails an increased level of expenditure but reduces the risk and uncertainty in the project for the IPP.



Source: Study Team

Figure 8-4-5.1 Roadmap for PV Investment by an IPP

Phase 1: Business Development (Required period of about 2 months)

Finding an IPP business opportunity and making a plan

- ✓ Identification of project opportunity & pre-screening
- ✓ Risk management
- ✓ Geographical market risk clearance
- ✓ Site identification
- ✓ Direct proposal or PPP

Phase 2: Pre-Feasibility Study (Required period of about 2 months)

- ✓ Site visit (initial survey) to identify key constraints and challenges and land lease/access, including boundary area concerns
- ✓ Conceptual design and assessment of various technical solutions, including grid connection
- ✓ Estimated cost plan for the project
- ✓ Estimated energy yield, PV system
- ✓ Estimated energy tariff based on incentives such as Feed-in Tariff and PPA.
- ✓ Identification of initial environmental and social impacts
- ✓ Studies on initial licensing and permitting, estimated cost, and estimated timelines
- ✓ Selection of the project structure

Phase 3: Feasibility Study (Required period of about 2 months)

- ✓ Development of the pre-feasibility study in detail
- ✓ Creation of a detailed permitting and licensing roadmap and initiation of discussions with stakeholders and all authorities with jurisdiction, in order to obtain consent

Phase 4: Contracts Close (Required period of about 6 months)

- ✓ Obtaining the relevant permits and licenses
  - • Land lease contract.
  - • Environmental impact assessment
  - • Building permit/planning consent
- ✓ Close Grid Connection Agreement and PPA
  - • Grid connection contract
  - • Power purchase agreement.

Phase 5: Construction (Required period of 12 months)

The management of the construction phase of a solar PV project should be in accordance with best practices for construction management. The aim should be to construct the project to the required level of quality within the time and cost deadlines.

Phase 6: Operation & Maintenance (20 years after the construction)

Compared to most other power-generating technologies, PV plants have low maintenance and servicing requirements. However, suitable maintenance of a PV plant is essential to optimize the energy yield and maximize the life of the system.

8-4-6 Tender Process

The following shows the competitive tender process conducted by PPUC / Energy Agency for IPP introduction.

Commence the Tender	・Provide details on the demand and supply of PV.
Due Diligence	・Interested IPPs submit required documents for tender. ・Conduct due diligence on the IPPs.
Decide the Successful bidder	・Dispatch an official request to the successful bidder.
Analyze the proposal	・Analyze the feasibility, tariff, and bankability of the successful bidder's proposal.
Approve the successful bidder	・Commence negotiations for a PPA.

8-4-7 Power Purchase Agreement (PPA)

While the IPP will handle the business development, the PPA will be of foremost importance as an agreement to be executed by both parties, PPUC and the IPP.

PPAs are legally binding agreements between a power seller and power purchaser (off-taker). In most cases with PV, the party selling the power is the owner of the solar PV plant. For renewables (including PV) that are supported by regulatory mechanisms, the most common option is to sell all electricity generated to a power company (vertically integrated, transmission or distribution), often to one that is wholly or partially owned by the government.

The PPA is the most important agreement for financing a solar PV project. All of the other related agreements such as the loan agreement and grid connection agreement should be aligned with the PPA. The PPA should define all of the commercial terms affecting the sale of electricity between the two parties, including the date the project will begin commercial operation, the schedule for delivery of electricity, the tariff, the volume of energy expected to be delivered, the payment terms, the penalties for underperformance on either side, and provisions for termination.

PPAs may be standardized[8] and non-negotiable (except possibly for the tariff), standardized to provide an initial framework for negotiations, or open to bilateral negotiations.

- Main Terms of a Power Purchase Agreement

  The PPA sets out the terms of the power purchase, including the tariff, the volume of power to be sold, and the duration of the agreement. Some of the key commercial, legal, and technical terms to be considered while reviewing a PPA are described below.

[8] Standard PPAs can be obtained through the World Bank website: https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements

(1) Tariff of Energy Sold

The methodology for calculating the electricity price will depend on the market within which the project is operating and the prevailing regulatory regime. Under a FIT regime, a flat-fixed rate price could be offered for the life of the project. Alternatively, the tariff may be set through a reverse auction, negotiated, or based on power market parameters (e.g., the marginal cost of power supply).

(2) PPA Duration

A PPA covering a 15- to 25-year period is desirable for a PV plant and is relatively common.

(3) Responsibility for supply

Under normal PPA contracts, the Electric Utility Provider (PPUC) bears the obligation to purchase and pay at a fixed price for renewable energy. While the IPP has a quantitative obligation (certain output/supply obligation), the IPP is not obliged to agree to an exclusive obligation (an obligation to supply the entire amount to the electric power company (the counterparty in the specific contract) or an obligation to restrict supply to a third party or wholesale electricity market other than the electric power company (the counterparty in the specific contract).

(4) Cost

The cost required to connect the PV power to the power transmission system is to borne by the IPP. If the IPP makes a request for connection, PPUC is to show reasonable evidence for the content of expenses, the basis of accounting, and the need for the expenses that it asks the IPP to bear.

PPUC, meanwhile, is to bear the costs for equipment and installation for facilities required for grid interconnection to receive PV power. PPUC has ownership of the equipment.

(5) Formulation of the grid code

It will be necessary to specify the rule for the system contribution required for PV generation as a grid code. The content of the grid code is updated from time to time while watching the status of PV generation and the electric power system. In other words, based on the technical trends, it will be necessary to clarify the specifications required for the grid-interconnected PVs by identifying the power quality to be required by the power system.

PPUC will formulate the grid code and seek compliance with the IPP.

(6) Output limit

The output limitation should be confirmed in a contract stipulating that the renewable energy electricity supplied by the IPP can be suppressed without compensation measures when the amount of electricity supply is expected to exceed a demand level that may trigger a power system failure.

(7) Taxes on sold electricity

Under the FIT system, the fixed electric wholesale price is applied during the contract period. The tax rate set for wholesale power is an important investment decision for the business operator.

8-4-8 Some Policies and Support Mechanisms for an IPP System

- Tax Incentives for IPPs

  The exemption or reduction of income tax over a certain period may attract IPPs. Customs exemptions or reductions for imported equipment may also be useful. Accelerated depreciation of invested assets for tax accounting is also useful.

- Payment guarantee by the government

  A government guarantee to IPPs for nonperformance of contractual obligations with government agencies and private entities.

- Guarantee from international organization

  If IPP concerns remain under government guarantee, guarantees can be obtained from international organizations (for example, a Partial Risk Guarantee from the World Bank).

- Political Risk Insurance (PRI)

  Political Risk Insurance (PRI) against the specific risks of transfer and convertibility, expropriation, war and civil disturbance, and breach of contract. The Multilateral Investment Guarantee Agency (MIGA) provides PRI.

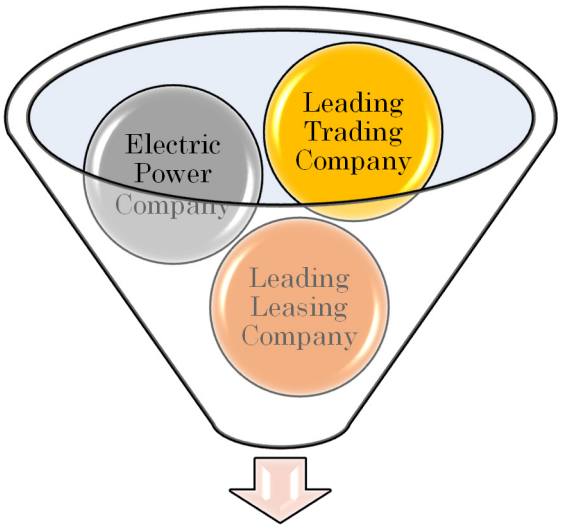
8-4-9 General Guidelines in the Regulatory Framework for IPPs

A regulatory framework should be set up for IPPs in a competitive and clean business environment.

- ✓ streamlined approvals process
- ✓ clarity on how businesses should be structured and licensed
- ✓ issuance of clear laws and regulations – ideally with official translations in English
- ✓ avoid changing goal posts after IPPs start operating

8-4-10 Interviews with IPPs

Interview surveys are conducted with IPPs already running RE power generation abroad. The target companies are trading companies, electric power companies, and leasing companies, all of which are large private enterprises. The surveys seek to sound out the IPPs' interest in entering the IPP business, the desirable business environment for investing, investment schemes, expected investment returns, and a time axis from business plans up to PV implementation.



Expected Business Environment in Palau for IPP Investment

(1) Trading Company

- The total of 44 MW generated by PV is small as an investment project. Normally, IPP projects exceeding 100 MW are treated as investment subjects. Major trading companies have advantages in size and financing for procurement costs in projects with large investment amounts. With the scale of this project, the superiority of the project cannot be utilized effectively for businesses with smaller turnover in bidding.
- Key factors for businesses making investment decisions are the commitment of business sites and guarantees of payment. Normally the decisions are reached with off-taker guarantees from the government. In the case of a country with no credit rating, however, it may be necessary to obtain the guarantee of an international organization, for example, a Partial Risk Guarantee from the World Bank. Other payment guarantees include bank letters of credit. All expenses for guarantee shall be borne by the recipient country.
- PV investment is implemented mainly in Middle Eastern countries where the size is large, the sunshine hours are stable, and the risk of power supply fluctuation risk is small. When there is a large risk of fluctuation in power generation due to the volatility of daylight hours, it becomes necessary to set a power selling price that reflects the risk.
- It generally takes 24 months from planning to the start of business. If a recipient country has no experience, however, a longer period might be required.
- Prepared data from the off-taker is necessary for the prompt planning of the investment. Data on land sites, weather conditions, sunshine conditions, and environmental factors are especially important. At this point, it is common to connect a non-disclosure agreement (confidentiality agreement).
- Before tender, surveys need to be conducted with external consultants, legal advisors, etc. to finish projects that can establish project viability for finance. The costs for the surveys will be borne by the operator.

- PV power is usually sold at a fixed price under a PPA. The period runs from 25 to 30 years in the case of the Middle East, and the fixed price is regularly adjusted according to the inflation of the host country.
- A project return of 10% is standard for an IPP investment. For the return of equity investment alone, a project return should preferably be greater than 20%.
- The preferred investment timing is to invest for all of the 44 MW at once rather than dispersing capital investment for each investment phase. In this way the IPP investor can avoid the risk of a business breakdown that would halt operations halfway.
- Major trading companies generally require no advisor services from international organizations because they already have knowledge of overseas IPPs with adequate experience. If the host country lacks a track record in IPP generation, however, the off-taker may use such advisory service at its own cost.

(2) Electric Power Company

- The IPP project is mainly thermal power generation, but RE will be a focus in the future. Investment in RE business overseas is mainly conducted in Europe, North America, and Asia. As for IPPs, Thailand has a track record of wind power generation of 180 MW and PV power generation of 30 MW.
- The investment scale and stability of the electricity sales market are important considerations for the selection of RE projects. With a size of 20 MW or less, it might be difficult to obtain sufficient investment returns in consideration of the cost of the business survey. Investment plans that can be expected to develop additional business projects based on RE investment are desirable. The offshore wind power generation targeted can be expected to reach a sufficient scale as a future overseas RE investment.
- The total 44 MW scale of the project for RE investment in Palau is not large enough for investment. In comparison with other projects, it cannot be selected as an investment case. If there are no additional related business opportunities in Palau.
- It will be desirable to make an IPP business plan with an MOU, government guarantee, and license certification. Concerning survey rights, coordination with the recipient government or prior approval in contracts is also desirable.
- As for overseas RE projects, pure capital investment is implemented through IPPs in host countries because actual business records of the initial planning and operation and maintenance work are not abundant. Power company is striving to acquire business know-how by sending personnel to RE IPPs.
- It takes from 6 months to 12 months from business planning to tender, then it takes another 3 months to conclude the borrowing agreement with a bank based on the term of the PPA. It will take 12 months to move to the start of business operations from the subsequent construction.
- The contractual term of the PPA is preferably 20 years. Also, the electric wholesale price will be fixed according to FIT. Price changes during the contract period are undesirable because they would make business revenue unpredictable.
- Investment returns as hurdles for business selection will be over 10% on a dollar basis.

- IPP projects are not implemented in PPP schemes utilizing advisory bodies such as the WB and ADB. International aid organizations are often involved in investment projects from which private-led initiatives cannot expect sufficient profit.

(3) Lease Company

- A total PV power generation level of 44 MW is small but can be considered an investment case if the leasing company can enter the business as a single business operator.
- If the bilateral credit system and NEXI's trade insurance are utilized, the project will have a highly realistic PV business plan in Palau.
- The overseas PV project will be planned for implementation from survey development, including operation management, in Palau. The standards for operation and maintenance work will be set up and the local maintenance work will be consigned to a local maintenance company.
- The return necessary for business investment is 10%. In the case of Palau, about 15% will be necessary given the profitability expected from the scale of the project and the risk of power generation fluctuation stemming from factors such as sunshine hours.
- It will be necessary to set a fixed wholesale price in the PPA and set a contract period 20 to 25 years for PV investment.
- Private consultants are used for IPP investment. However, the use of advisory services from international organizations such as the ADB is not planned at the moment.
- The period required for preparation from planning to tender bidding will be at least 6 months. It will be necessary to complete the project within 12 months from the completion of the tender.

8-4-11 Expected Investment Return of IPPs

PV Investment by private IPPs are planned based on pure business profitability, not in relation to international development assistance. On the other hand, the Master Plan by the Study Team is a donor project for development assistance to be implemented under a comprehensive re-energy plan and integrated with the power transmission network renewal and system planning. Further, this IPP investment analysis is based on this master plan. For these reasons, private IPP capital investment may differ greatly from the capital investment planned by this survey. Hence, the results of the economic analysis of this study may not apply directly to private IPP investment for pure business purposes.

Investment feasibility for an IPP is judged from the cost required for RE investment and the revenue generated by the RE project. In this case, the cost is the investment cost and maintenance cost calculated in FIRR, and the income is revenue from wholesale electricity sales, i.e., the wholesale power sales volume (kWh) x wholesale electricity price ($ / kWh). The investment return is shown in the Figure 8-4-11.1.below.

Source: Study Team

Figure 8-4-11.1 Investment return of IPP for each wholesale electricity price scenario

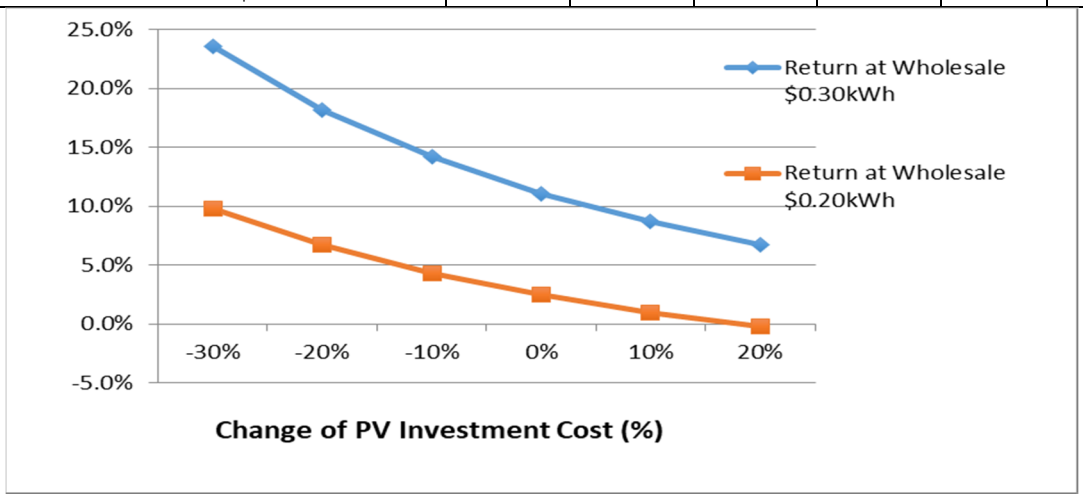
8-4-12 Comparison of Investment Return by the Investment Amount

The investment returns obtained by an IPP are greatly influenced by changes in capital investment. The table and figure below show a comparison of investment returns when PV capital investment fluctuates from minus 30% to plus 20%, rather than the ranges set in the original plan (Table 8-4-12.1 and Figure 8-4-12.1).

For example, if the wholesale electricity price is 0.20 kWh, the investment return can reach 9.6% when the capital investment amount decreases by 30%.

Table 8-4-12.1 Comparison of investment return according to changing investment amounts

Change of PV Investment Cost	-30%	-20%	-10%	0%	10%	20%
Project Return at Wholesale $0.30 kWh	23.6%	18.2%	14.2%	11.1%	8.7%	6.7%
Project Return at Wholesale $0.20 kWh	9.8%	6.7%	4.3%	2.5%	1.0%	-0.2%



Source: Study Team

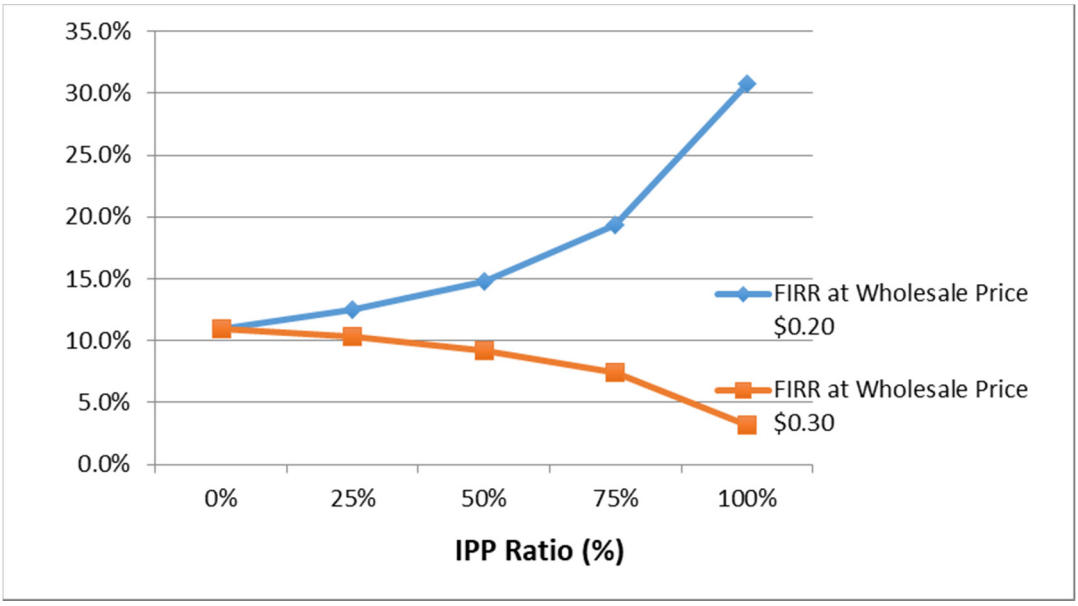
Figure 8-4-12.1 Comparison of investment return according to changing PV investment amounts

8-4-13 Financial Effect on PPUC after an IPP Introduction

The table and figure below show the FIRR returns of the PPUC Master Plan based on different IPP introduction ratios in the PV market. The FIRR calculation sets the wholesale IPP price at $0.40kWh and the power tariff for the final consumer at 0.32 kWh (Table 8-4-13.1 and Figure 8-4-13.1).

Table 8-4-13.1 PPUC FIRR according to each IPP PV market ratio

IPP Ratio	0%	25%	50%	75%	100%
FIRR at IPP Price $0.20	11.0%	12.5%	14.8%	19.3%	30.8%
FIRR at IPP Price $0.30	11.0%	10.3%	9.2%	7.4%	3.2%



Source: Study Team

Figure 8-4-13.1 PPUC FIRR according to each IPP PV market ratio

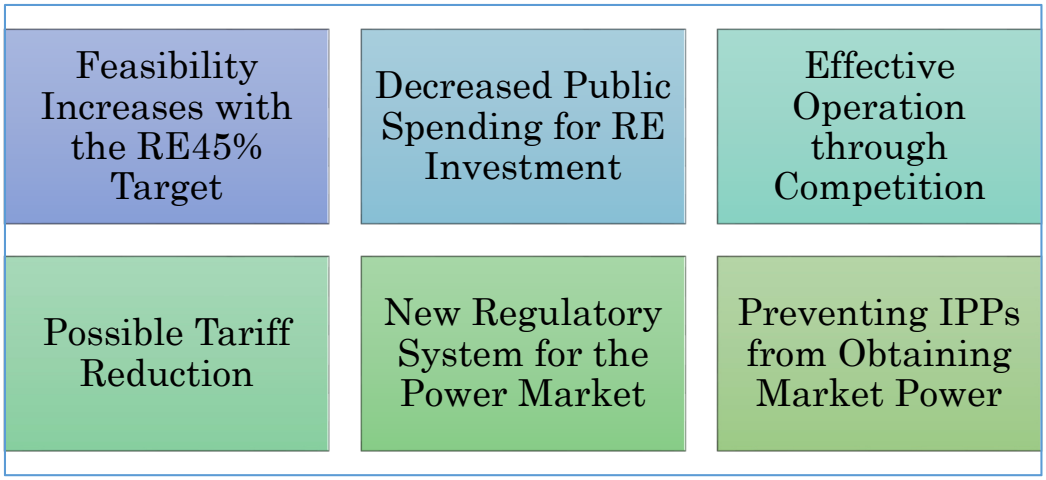
If the purchase price from IPP is $0.30 kWh, FIRR goes lower when IPP ratio is high, as the IPP wholesale price is higher than the current DEG cost. The FIRR, on the other hand, will be higher with an IPP price of $0.20, given that IPP ratio as wholesale price is much cheaper than the tariff rate.

8-4-14 Considerations on IPP Operation in the Palau PV Market

The following issues will arise in relation to the economic effects from the introduction of an IPP system in Palau.

- The possibility of achieving the Palau national target of 45% RE increases. The amount of PV investment necessary for the Master Plan can easily be invested by major IPPs. The financing burden on PPUC and the Palau government for securing funds through the introduction of IPP is lightened.
- Monetary expenditure occurs only when electricity is provided to the PPUC by private enterprises. The Palau government can therefore secure a national budget that can be allocated to public services other than electricity.

- Due to the ongoing PV technological innovation, PV capital investment expenses will be reduced from the initial forecast, which will lead to an expected reduction of the PV power generation cost. Moreover, by introducing the market principle, the efficient business operations of private enterprises could potentially make Palau's electricity business more efficient.
- If the price of electricity purchased from IPPs is lower than the power generation cost by DEG for PPUC, the business profit will increase, which in turn will permit a lower tariff for the final customer. On the contrary, if the IPP price exceeds the current DEG cost, it will be necessary to raise the tariff for the consumer.
- Open and fair RE development under the control of independent regulatory bodies is necessary for promoting the IPP market. If the power market system and capital market are insufficiently developed, the rapid entry of IPPs into the RE market may lead to manipulation of the power supply by specific enterprises. It will also be necessary, for a fair and an efficient electric market, to consider an appropriate ratio of IPP entry in order to prevent monopoly and oligopoly by specific IPPs.
- If all of the RE power generation is owned by IPPs, the monopoly of PPUC in the current Palau Power Project will be converted to a private monopoly in the RE market. It will therefore be necessary for PPUC to own a certain market share of RE power generation facilities. This arrangement will assure a stable power supply. PPUC can also hold price-bargaining power for negotiating with IPPs if they pursue excessive business profits.



Source: Study Team

Figure 8-4-14.1 Effects of IPP entry in the power market

Appendix: IRR Calculation Table

FIRR

#	Year	Annual Power Supply (kWh)	PV Ratio	POWER Supply by PV (kWh)	Cap. Exp. Ratio(%)	Cap. Exp. For PV($)	PV O&M Cost($)	Battery O&M Cost($)	Fuel cost for DEG Generation ($)	Cap. Expenditure for Transmission & Sub Station	DEG Generation O&M Cost	Transmission O&M Cost ($)	Total Cost($)
			PV Ratio		Invest. Term	RE Total Cap. Exp.	O&M Cost (USD, kWh)	Battery O&M Cost	Fuel Cost	Dist/Trans Total Cap. Exp.	Generation O&M for DEG	Trans & Distri. Cost ($/kWh)	
			45%		8	112,305,000	2%	2%	0.177	35,000,000	0.05	0.03	
		Annual Electric Power Supply (kWh)			Cost for RE (PV)								
	2015	66,742,655		0	0	0							
	2016	70,736,974		0	0	0							
	2017	72,461,239		0	0	0							
8	2018	74,267,902	9%	6,387,040	8.3%	9,332,879	186,658	0	12,014,913	1,810,000	3,394,043	2,228,037	28,966,529
7	2019	77,021,148	13%	9,704,665	7.4%	8,315,098	345,122	7,837	11,915,018	10,498,000	3,394,043	2,310,634	36,785,753
6	2020	81,736,310	19%	15,529,899	9.5%	10,646,428	547,452	18,436	11,718,535	5,792,000	3,394,043	2,452,089	34,568,983
5	2021	84,547,022	20%	16,740,310	0.3%	285,000	552,871	18,717	12,001,788	1,140,000	3,394,043	2,536,411	19,928,830
4	2022	86,832,808	26%	22,316,032	9.3%	10,445,701	751,738	28,765	11,419,469	6,612,000	3,394,043	2,604,984	35,256,700
3	2023	90,209,089	34%	30,310,254	24.2%	27,233,399	1,173,097	152,073	10,602,094	3,648,000	3,394,043	2,706,273	48,908,979
2	2024	92,839,412	41%	38,435,517	23.1%	25,941,098	1,557,203	286,789	9,629,489	1,705,000	3,394,043	2,785,182	45,298,805
1	2025	97,117,459	45%	43,411,504	17.9%	20,105,397	1,828,887	417,213	9,505,954	3,795,000	3,394,043	2,913,524	41,960,017
5	2026	98,589,519	45%	44,069,515			1,828,887	417,213	9,650,041		3,394,043	2,957,686	18,247,869
4	2027	100,524,846	45%	44,934,606			1,828,887	417,213	9,839,472		3,394,043	3,015,745	18,495,361
3	2028	102,321,971	45%	45,737,921			1,828,887	417,213	10,015,377		3,394,043	3,069,659	18,725,179
2	2029	103,971,216	45%	46,475,133			1,828,887	417,213	10,176,807		3,394,043	3,119,136	18,936,086
1	2030	105,430,051	45%	47,127,233			1,828,887	417,213	10,319,599		3,394,043	3,162,902	19,122,643
		684,571,150		182,835,220	100%	112,305,000	6,943,028	929,830	88,807,260	35,000,000	27,152,345	20,537,135	291,674,597
	NPV	465,723,935	NPV	113,268,298									

Year	Annual Revenue($)	Annual Revenue($) by PV	Improved Supply Revenue by Transmission	Power Cost paid to IPP	Net income with Salvage Value	Net income with Salvage Value	Net income-dist.cost - Fuel cost saved
	Average Tariff (USD, kWh)		Improved ratio by Trans.	Wholesale by IPP	FIRR for PPUC	FIRR with IPP	Project FIRR for IPP
	0.300		0.00%	0.300	11.0%	3.2%	11.1%
2015	0				0		
2016	0				0		
2017	0				0		
2018	22,280,371	1,916,112	0	1,916,112	(6,686,159)	917,266	(7,603,424)
2019	23,106,344	2,911,399	0	2,984,184	(13,679,409)	(7,995,535)	(5,756,658)
2020	24,520,893	4,658,970	0	4,894,830	(10,048,090)	(3,730,604)	(6,553,347)
2021	25,364,107	5,022,093	0	5,408,245	5,435,277	883,620	4,165,505
2022	26,049,842	6,694,810	0	7,389,817	(9,206,858)	(5,370,471)	(4,531,394)
2023	27,062,727	9,093,076	0	10,287,981	(21,846,252)	(3,575,664)	(19,465,493)
2024	27,851,824	11,530,655	0	13,372,025	(17,446,981)	(3,033,916)	(16,254,435)
2025	29,135,238	13,023,451	0	15,480,791	106,999,382	24,720,551	79,821,491
2026	29,576,856	13,220,854	0	16,108,327	11,328,986	(2,533,241)	10,974,754
2027	30,157,454	13,480,382	0	16,835,150	11,662,093	(2,926,957)	11,234,282
2028	30,696,591	13,721,376	0	17,564,522	11,971,412	(3,347,010)	11,475,276
2029	31,191,365	13,942,540	0	18,293,821	12,255,279	(3,792,442)	11,696,440
2030	31,629,015	14,138,170	0	19,014,267	12,506,372	(4,261,795)	11,892,070
	205,371,345		0		Total		
			0				

PV Working Life	Transmission Working Life	Battery Cost/Total PV Cost
17	40	
Salvage Value	Salvage Value	
4,940,936	1,448,000	0.00
4,891,234	8,660,850	0.05
6,888,865	4,923,200	0.05
201,176	997,500	0.05
7,987,889	5,950,800	0.05
22,427,505	3,374,400	0.23
22,889,204	1,619,750	0.26
18,922,726	3,700,125	0.32
0	0	0.32
0	0	0.32
0	0	0.32
0	0	0.32
0	0	0.32
Total Salvage Value: 89,149,536	30,674,625	

0.19116

Economic IRR

Year	Benefits from RE Supply($)	Fuel Cost Saved ($)	Benefits from Tranmission rennovation	Benefits from GNI by reduced B.O.	CO2 Reduction Value ($)	Total Benefits	Adjusted O&M Cost by SCF	Capital Expenditure for PV & Transmission	Net Benefit with Salvage value
	Economic Benefit by RE ($/kWh)	Fuel Cost Saved ($/kWh)	Blackout Reduced	GNI Improved	CO2 Trade Price ($/ton)		Standard Conversion Factor	RE Total Cap. Exp.	Economic IRR for PPUC
	0.300	0.177	0.12%	211,225	19.00		0.9	112,305,000	8.8%
2018	541,999	1,130,506	88,392	211,225	127,089	2,099,211	340,442	11,142,879	(9,384,110)
2019	1,367,973	1,717,726	91,669	211,225	186,200	3,574,793	579,690	18,813,098	(15,817,995)
2020	2,782,521	2,748,792	97,281	211,225	280,778	6,120,597	928,607	16,438,428	(11,246,437)
2021	3,625,735	2,963,035	100,626	211,225	292,600	7,193,221	966,418	1,425,000	4,801,804
2022	4,311,471	3,949,938	103,347	211,225	379,789	8,955,769	1,304,985	17,057,701	(9,406,917)
2023	5,324,355	5,364,915	107,365	211,225	496,533	11,504,394	2,011,030	30,881,399	(21,388,036)
2024	6,113,452	6,803,086	110,496	211,225	611,800	13,850,059	2,697,352	27,646,098	(16,493,390)
2025	7,396,866	7,683,836	115,587	211,225	665,000	16,072,515	3,193,601	23,900,397	108,802,679
2026	7,838,484	7,800,304	117,339	211,225	675,080	16,642,432	3,211,367	0	13,431,065
2027	8,419,082	7,953,425	119,643	211,225	688,332	17,391,707	3,234,724	0	14,156,983
2028	8,958,220	8,095,612	121,782	211,225	700,637	18,087,476	3,256,414	0	14,831,062
2029	9,452,993	8,226,099	123,745	211,225	711,930	18,725,992	3,276,319	0	15,449,673
2030	9,890,644	8,341,520	125,481	211,225	721,919	19,290,789	3,293,925	0	15,996,864
			0					147,305,000	

	CRF	LRMC for Master Plan	LRMC for RE generation	LRMC for Transmission & Substation	DEG annual O&M	DEG annual Fuel	LCOE
	9%	0.287	0.273	0.051		0.177	0.200
1	1.09000	29,388,514	10,340,830	3,978,133	5,622,080	12,014,913	22,355,742
2	0.56847	28,061,552	5,044,538	8,047,358	5,704,678	11,915,018	16,959,556
3	0.39505	23,983,432	4,715,221	4,495,038	5,846,132	11,718,535	16,433,756
4	0.30867	18,293,479	602,400	2,634,652	5,930,454	12,001,788	12,604,188
5	0.25709	21,906,452	3,387,963	4,044,381	5,999,027	11,419,469	14,807,432
6	0.22292	24,169,106	7,263,517	3,248,857	6,100,316	10,602,094	17,865,610
7	0.19869	22,343,403	6,813,843	2,845,431	6,179,225	9,629,489	16,443,332
8	0.18067	21,522,443	5,654,020	3,307,831	6,307,567	9,505,954	15,159,974
9	0.16680	17,388,086	2,021,490	2,661,917	6,351,729	9,650,041	11,671,531
10	0.15582	17,629,772	2,021,490	2,714,171	6,409,788	9,839,472	11,860,962
11	0.14695	17,854,199	2,021,490	2,762,693	6,463,702	10,015,377	12,036,867
12	0.13965	18,060,158	2,021,490	2,807,223	6,513,180	10,176,807	12,198,297
13	0.13357	18,242,339	2,021,490	2,846,611	6,556,945	10,319,599	12,341,089
	Total	189,668,382	43,822,332	32,601,680			132,629,591
	NPV (Cost)	133,732,893	30,898,567	23,542,805		NPV (Cost)	93,283,214
	NPV(Electric	465,723,935	113,268,298			NPV(Electrici	465,723,935