Independent State of Papua New Guinea
PNG Power Ltd.

THE PROJECT FOR FORMULATION OF RAMU SYSTEM POWER DEVELOPMENT MASTER PLAN AND LAE AREA DISTRIBUTION NETWORK IMPROVEMENT PLAN

FINAL REPORT

PART B : DISTRIBUTION NETWORK IMPROVEMENT PLAN IN LAE AREA

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The Project for Formulation of Ramu System Power Development Master Plan and Lae Area Distribution Network Improvement Plan

FINAL Report
Part B : Distribution Network Improvement Plan in Lae Area

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Abbreviations

Symbol	Abbreviations
AA	Aluminum conductors
AAC	All-aluminum conductors
ABS	Air-Break Switch
ACSR	Aluminium Conductor Steel Reinforced
ADB	Asian Development Bank
AIS	Air-insulated Substation
ASCR/GZ	Aluminum Standard Conductors Galvanized steel-reinforced
AutoCAD	Computer-Aided Design
C/S	Construction Stage
CB	Circuit Breaker
CEPA	Conservation and Environment Protection Authority
CSS	Community Support Service
CT	Current Transformer
D/L	Distribution Line
DAS	Distribution Automation System
DOF	Dropout Fuse
DSM	Demand Side Management
EIA	Environmental Impact Assessment
EIR	Environmental Inception Report
EIRR	Economic Internal Rate of Return
EIS	Environmental Impact Statement
EMP	Environmental Management Plan
ENPV	Economic Net Present Value
FIRR	Financial Internal Rate of Return
FYPDP	Fifteen Year Power Development Plan
GST	Generation-skipping tax.
GIS	Gas Insulated Switchgear
H.V.	High Voltage
IEC	International Electrotechnical Commission
IEE	Initial Environmental Examination
ILG	Incorporated Land Group
IPP	Independent Power Producer
IRR	Internal Rate of Return
Ithd	I Total Harmonic Distortion
ITIC	Information Technology Industry Council
JICA	Japan International Cooperation Agency

Symbol	Abbreviations
L.V.	Low Voltage
LBS	Load-Break Switch
LLG	Local Level Government
MOU	Memorandum of Understanding
O&M	Operation and Maintenance
OJT	On the Job Training
P/S	Power station
PF	Power Factor
POM	Port Moresby
PPL	PNG Power Limited
RMS	Root Mean Square
ROW	Right of Way
S/S	Substation
S/W	Switchyard
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCF	standard conversion factor
SCADA	Supervisory Control And Data Acquisition
SEA	Strategic Environmental Assessment
SDR	Social Discount Rate
SPM	Suspended Particle Matters
SSS	Sequential Switching System
STATCOM	Static Synchronous Compensator
T/L	Transmission Line
TMS	Time Multiplier Settings
Uthd	U Total Harmonic Distortion
VT	Voltage Transformer
WACC	Weighted Average Cost of Capital
UAGO	Union Attorney General Office

CHAPTER 1

INTRODUCTION

CHAPTER 1 INTRODUCTION

1.1 OBJECTIVE OF THE SERVICES

The objective of the Services is to contribute to the stabilization of the future power supply in Lae through the implementation of the Lae Area Distribution Network Improvement Plan (from 2016 to 2030).

1.2 OUTLINE OF THE STUDY

Item	Content	Remarks
Objective	Improved stabilization of the long-term status of the power supply in Lae and surrounding areas.	
Outputs	A distribution network improvement plan will be developed in the Lae area over the period from 2016 to 2030.	
Target area for project coverage	Lae Area (Lae City, Nadzab, Erap, Taraka, etc.)	
Implementing agency	PNG Power Ltd. (PPL)	
Scope of the Services	Lae Area Distribution Network Improvement Project	

1.3 IMPLEMENTATION STRUCTURE FOR THE STUDY

PPL is in charge of the implementation of this Study and counterpart agencies and officers from the PPL Head office are assigned as members. Table 1.3-1 is a list of counterpart officials taking part as members. The implementation structure of JICA Study Team is shown in Fig. 1.3-1.

Table 1.3-1 Member List of Local C/Ps

Organization	Name	Position
PPL Head Office	Mr. Chris Bais	Project Director
	Mr. Francis Uratun	Project Manager
	Mr. Andrew Yuants	Network Planning Engineer
	Mr. Kero Tom	Financial Expert
	Mr. Damien Sonny	Renewable Energy & Carbon Specialist
	Mr. Maira Pulayasi	Distribution Engineer
	Mr. Titus Tsigese	Environmental Expert

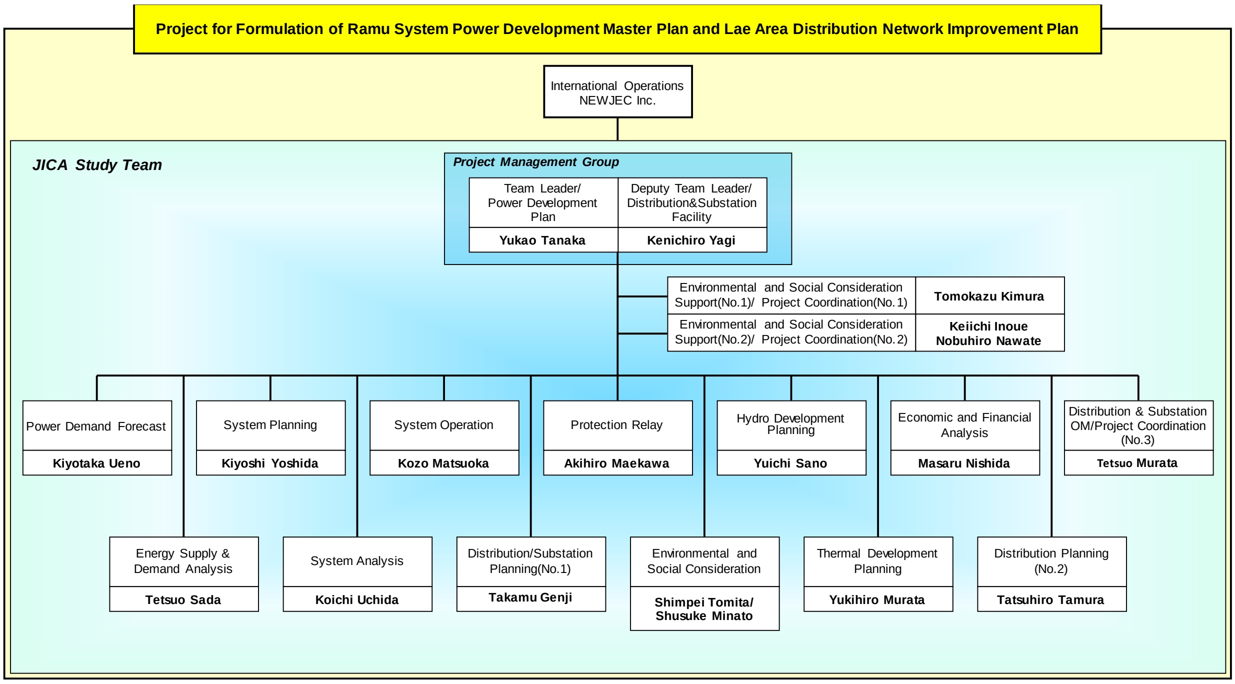


Fig. 1.3-1 Implementation Structure of JICA Study Team

1.4 OVERALL WORK SCHEDULE FOR THE STUDY

The Study is roughly divided into three stages, namely, “collection and analysis of basic information” “Formulation of distribution network improvement plan” and “Technical guidance on distribution network”. The major work items and timing are shown in Fig. 1.4-1 and the Main Study Components and Schedule are presented in Fig. 1.4-2.

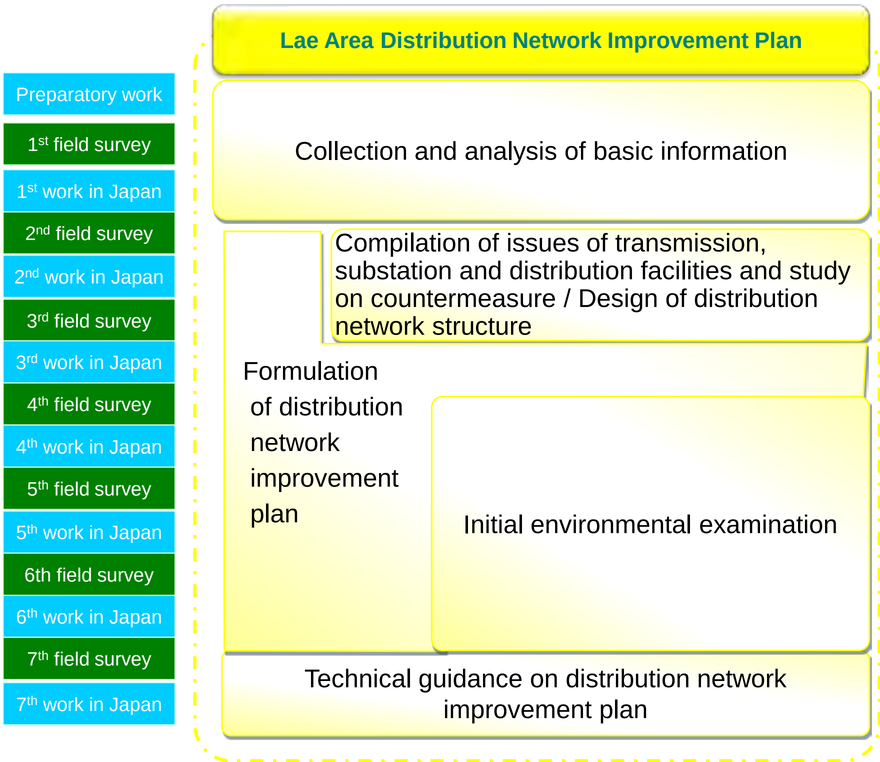


Fig. 1.4-1 Overall Work Flowchart

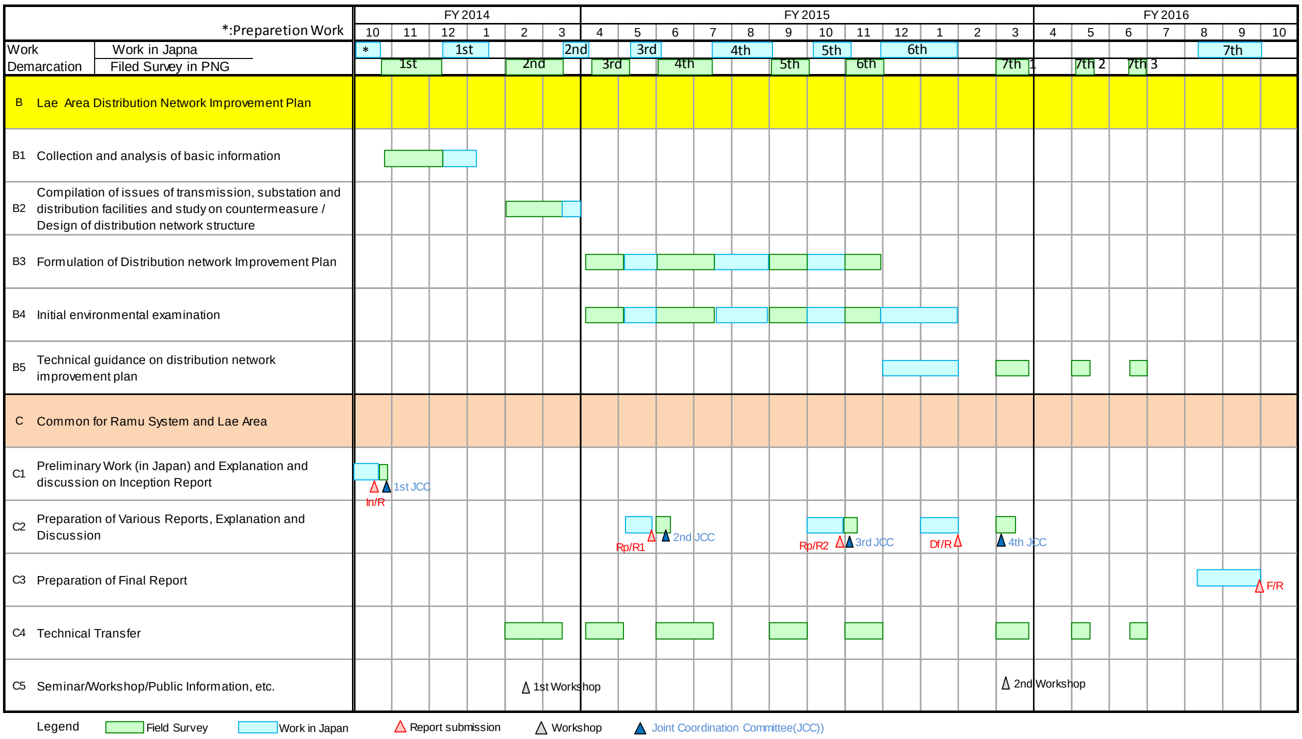


Fig. 1.4-2 Main Study Components and Schedule

CHAPTER 2

COLLECTION AND ANALYSIS OF BASIC INFORMATION OF THE LAE AREA DISTRIBUTION NETWORK

CHAPTER 2 COLLECTION AND ANALYSIS OF BASIC INFORMATION OF THE LAE AREA DISTRIBUTION NETWORK

2.1 OUTLINE OF THE POWER NETWORK IN THE LAE AREA

Lae city is the provincial capital of Morobe Province (population of about 650,000) and the second largest city in Papua New Guinea (PNG) with a population of over 120,000.

The power network of Lae area comprises of three power stations (P/S), 132/66kV transmission lines (T/Ls) mainly and plural substations. Of the substations, diesel generators are installed at Taraka and Milford substations. Distribution network are connected to each consumer after stepping down to 240 V / 415 V distribution transformers from 11kV and partly 22kV distribution lines (D/Ls). Power is also supplied to some large power consumers through 11kV lines directly.

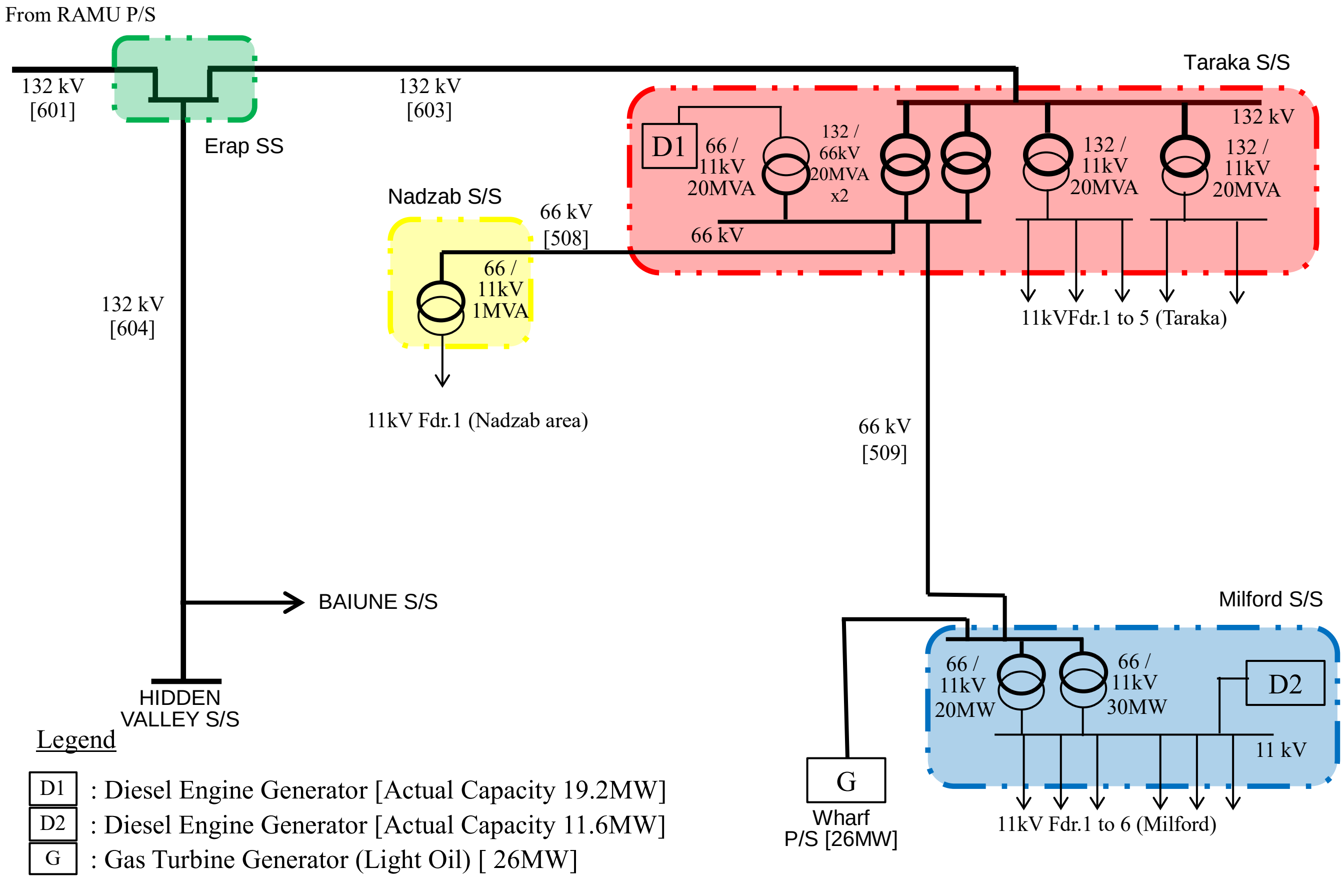


Fig. 2.1-1 Outline of the Power Network Facilities in the Lae Area

* Voltage of Transmission line [508] was changed from 66kV to 11kV.

2.1.1 Outline of Transmission Facilities in the Lae Area

(1) 132kV transmission lines [603]

The existing 132kV single-circuit T/L is mostly running along the Markham River together with the Highlands Highway.

Power is transmitted to the backbone substation (Taraka substation) from Ramu P/S and others located outside Morobe Province via roughly 160 km of 132kV T/Ls, after that power is supplied to each consumer from the Taraka substation.

(2) 66kV transmission lines

1) Taraka S/S – Nadzab S/S line [508]

The existing 66kV single-circuit T/L is mostly running along the Highlands Highway.

2) Taraka S/S – Milford S/S line [509]

There is an existing 66kV single-circuit T/L to the Milford substation in the center part of the Lae city.

3) Milford S/S – Wharf P/S line

There is an existing 66kV single-circuit transmission to Wharf P/S near the seaboard region in Lae city. This T/L was commissioned in 2015.

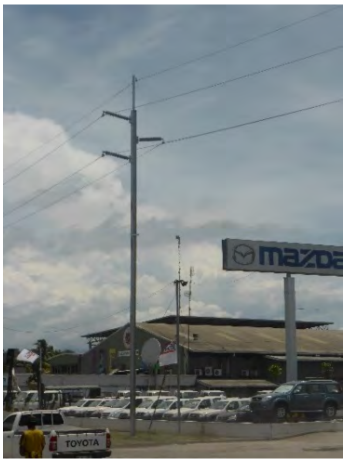
Fig. 2.1-2 66kV Transmission Lines Route

Table 2.1-1 Transmission Lines in the Lae Area

NO.	Sections		Voltage (kV)	Line ID	Length (km)	Number of Circuits	Conductors
	From	To					
1	Singsing point	Erap SW	132	601	96.9	1	ACSR Deer
2	Erap SW	Taraka S/S	132	603	40	1	ACSR Deer
3	Erap SW	Hidden Valley S/S	132	604	110	1	ACSR Sapphire
4	Taraka S/S	Milford S/S	66(11)	509	4.6	2	ACSR Camel/Tiger
5	Taraka S/S	Nadzab S/S	66	508	36	1	ACSR Milk
6	Taraka S/S	Wharf P/S	66			1	

As of March 2015, Source: JICA Study Team

132kV Line (Near Taraka S/S) 66kV Lines [508 & 509]



66kV Line [509] (in the city) 66kV Milford S/S – Wharf P/S line

Fig. 2.1-3 Photographs of 66kV Transmission Lines

2.1.2 Outline of Substation Facilities in the Lae Area

Substations in the Lae area are shown in Table 2.1-2, Fig. 2.1-4 and Fig. 2.1-5.

Table 2.1-2 Substations in the Lae Area

No.	Name	Voltage ratios (kV)	Number of transformer units	Unit capacity (MVA)	Total capacity (MVA)
1	Taraka S/S	132/11	2	20	40
		132/66	2	20	40
2	Milford S/S	66/11		30/20	50
4	Nadzab S/S	66/11	1	1	1
5	Hidden Valley S/S	132/11	2	25	50

As of March 2015, Source: JICA Study Team

(1) Taraka substation

Taraka S/S (132/66/11kV) is located in the northwestern suburb of Lae city.

Taraka S/S is one of the key substations in the Ramu grid to supply bulk electric power to Lae and was commissioned in the early 1970s.

There is one 132kV T/L bay for Erap S/S, two 66kV T/L bays for Milford and Nadzab S/S and five 11kV distribution feeders. There are two units of 132/66kV, 20 MVA auto-transformers and two units of 132/11kV, 20 MVA main transformers. The latter transformers are operated in parallel. A single bus bar system is applied for both 132 and 66kV switchyards. The Static Synchronous Compensator (STATCOM) of 132kV, 10 MVar was commissioned in 2012.

(2) Milford substation

Milford S/S (66/11kV) is located at the center of Lae in Lae city. Milford S/S is also one of the key substations in the Ramu grid supplying bulk electric power to Lae city.

There are two 66kV T/L bays for Taraka S/S and Wharf P/S and six 11kV distribution feeders. There is one unit of 66/11kV, 20 MVA main transformer and one unit of 66/11kV 30 MVA main transformer, which are operated in parallel.

(3) Nadzab substation

Nadzab S/S (66/11kV) is located near Nadzab airport. Nadzab S/S is also one of the key substations, because it supplies Nadzab airport.

There is one 66kV T/L bay for Taraka S/S and one 11kV distribution feeder. There is one 66/11kV, 1 MVA transformer.

(4) Erap switching station

Erap switching station, which switches 132kV T/Ls, is located in Markham Valley of Morobe Province, which is about 40 km from Lae city in a west-northwestern direction. Erap switching station is one of the newest substations in the Ramu grid, commissioned in December 2010. There are three 132kV T/L bays in the switchyard, including one each for the Ramu 1 switchyard, Taraka S/S and Hidden Valley S/S. The one-and-a-half circuit breaker bus bar scheme is applied to the existing 132kV switchyard.

Fig. 2.1-4 Location of Key Substations


Erap SW Nadzab S/S


Transformer of Taraka S/S Transformer of Milford S/S

Fig. 2.1-5 Photographs of Key Substations

2.1.3 Outline of Distribution Network Facilities in the Lae Area

Lae city is the largest load center in the Ramu system. Three substations, Taraka, Milford and Nadzab and a total of twelve 11kV D/Ls currently supply power to the Lae area. These include two tie transformers (22/11kV) on distribution feeders, one on the D/L No. 1 from Nadzab substation and the other D/L No. 6 from Milford substation.

In the urban area, including Lae city, power is supplied from Taraka and Milford substations by eleven 11kV D/Ls. In the rural area, two (2) 22/11kV D/Ls from Nadzab and Milford substations operate. Though the D/L installed in Lae city is designed for an insulation level of 22kV, it is operated at 11kV.

Summary of D/L in the Lae area are shown in Table 2.1-3 and Table 2.1-4 and Fig. 2.1-6.

Table 2.1-3 Number of H.V. Distribution Lines in the Lae Area

(Unit: km)

	22kV H.V. line	11kV H.V. line	Remarks
Taraka S/S	0	5	
Milford S/S	(1)	6	One Tie transformer (22/11kV) on fdr. No.6
Nadzab S/S	(1)	1	One Tie transformer (22/11kV) on fdr. No.1
Total	(2)	12	

Fig. 2.1-6 Distribution Line in the Lae Area

Souse: JICA Study Team, As of May 2015

Table 2.1-4 Summary of H.V. Distribution Line Lengths in the Lae Area

(Unit: km)

	Urban area	Rural area	Total
11kV Distribution line	91	8	99
22kV Distribution line	0	88	88
Total	91	96	187

Urban area

Rural area

Fig. 2.1-7 Photographs of the Distribution Network in the Lae Area

2.2 DISTRIBUTION NETWORK OF PPL

2.2.1 Existing Distribution Facilities

(1) High-voltage distribution line system

The basic configuration of the high-voltage distribution system is as follows:

1) Type A: 132kV Transmission line to 11/22kV distribution line

Cases in which the voltage is stepped down from 132 to 11kV in the primary (main) substation and supplied to secondary (distribution) substations via 11 / 22kV lines

2) Type B: 132kV Transmission line to 11/22kV distribution line though 66kV transmission line

Cases in which the voltage is stepped down from 132 to 66kV in the main substation and supplied to demand areas via 66kV T/Ls, then further stepped down to 11/22kV to be carried via 11kV D/Ls to secondary substations.

Type A (11kV) applies to most residential zone in Lae city, type B (11kV) is for an overcrowded zone in Lae city. In more remote areas such as Nadzab, cases of type B (22kV) predominate.

In the case of some D/Ls in the new development area, the voltage drop is excessive or close to excessive and upgrading to 33 or 22kV D/Ls is under consideration.

As for configuration, the high-voltage D/Ls tend to have a radiant pattern.

(2) Low-voltage distribution lines

The nominal low-voltage value in PPL is 415/240 V. There are from two to five low-voltage distribution (feeder) lines from each distribution substation, in a radiant pattern.

2.2.2 Distribution Technical Standards

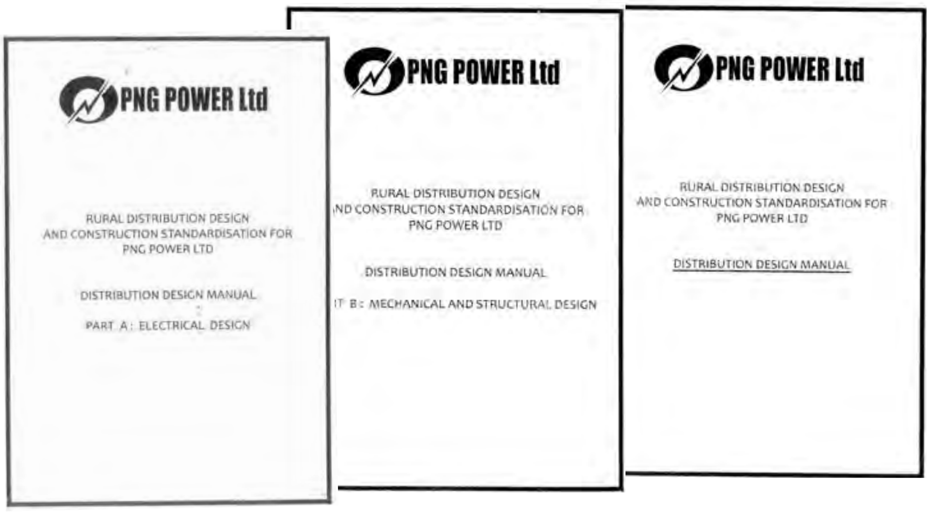
The technical standards for distribution facilities are set down in the distribution design manuals determined by the Papua New Guinea Electricity Commission in 1989. PPL applies the same standards. Distribution Design Manuals are shown in Table 2.2-1 and Fig. 2.2-1.

These specifications include general standards for voltage, frequency and electrical design parameters, refer to Table 2.2-2.

Table 2.2-1 List of Distribution Design Manuals

No.	Contents of Distribution Design Manuals
Part A	Electrical design
Part B	Mechanical and structural design
Distribution Design Manual	

Source: PPL



Source: PPL

Fig. 2.2-1 Distribution Design Manuals

Table 2.2-2 Example Electrical Design Parameters described in PPL Standards

No.	Items	33kV System	22kV System	11kV System
High Voltage				
1	Nominal system voltage	33kV	22kV	11kV
2	Maximum system voltage	36kV	24kV	12kV
3	Type of system grounding	Solid	Solid	Solid
4	Basic impulse level peak	170kV	150kV	75V
5	Rated fault level at nominal voltage (3-phase symmetrical)	750 MVA 13.12kA	500 MVA 13.12kA	250 MVA 13.12kA
6	Transformer insulation level (phase/neutral)	170/70kV	150/50kV	75/28kV
7	Surge arrester rated voltage (rms)	30kV	21kV	10. 5kV
8	Surge arrester front-of-wave impulse spark over	150kV	88kV	44kV
9	One minute power frequency withstand of switchgear	70kV	50kV	28kV
10	Insulator creepage	660mm	440mm	220mm
Low Voltage				
1	Nominal system voltage	415/240V		
2	Maximum system voltage	436/252V		
3	Type of system grounding	Earthed neutral		
4	System frequency	50 Hz		
5	One minute test voltage	2,000V		
6	Impulse withstand voltage (1.2/50 wave)	6,000V		

Source: Distribution Design Manuals, Part A Electrical design: Page A3.8, PPL

2.2.3 Distribution Facility Design Standards

The following parameters are defined in the design standards:

(1) Conductors

A selection of H.V. conductor size is shown in Table 2.2-3.

Table 2.2-3 Selection of H.V. Conductor Size

	Condition	Conductor Type	Conductor Code Name	Conductor Size
1.	Feeders	AA	Saturn	37 / 3.00
2.	11kV Urban Distributors and Spurs with loads over 50kVA*	ACSR	Cherry	6 / 4.75 + 7 / 1.60
3.	11kV Urban Distributors and Spurs with loads under 50kVA**	ACSR	Apple	6/1/3.00
4.	22kV Rural Feeders ***	ACSR	Cherry	6/4.75+7/1.60
5.	22kV Rural Distributors and Spurs with loads over 50kVA ***	ACSR	Apple	6 / 1 / 3.00
6.	22kV Rural Spurs with loads under 50kVA ***	ACSR	Raisin	3 / 4 / 2.50

* For loads over 100kVA for 22kV and 150kVA for 33kV
** For loads under 100kVA for 22kV and 150kVA for 33kV
*** All rural distribution H.V. lines to be 22kV

AA : Aluminum conductors
ACSR : Aluminum conductors steel-reinforced

Source: Distribution Design Manuals, Part A Electrical design: Page A6.3, PPL

(2) Insulators

The following types of high voltage insulators will be used:

strain insulators — for suspension or termination poles
pin insulators — for crossarm mounting applied to straight line sections

In addition, guy insulators will be employed to insulate the upper half of stays for high-voltage wood poles.

(3) Distribution Switchgear

Switching, sectionalizing and isolating on the High Voltage (H.V.) system should be performed via outdoor pole top-mounted air-break switches (load break switches to IEC 129). In addition, pole-mounted auto-reclosers may be installed at strategic points. Spurs may be protected and isolated by dropout fuses.

(4) Air-Break Switches

Air-break switches may be installed for the following reasons:

(i) To isolate system sections so that maintenance and other work can be performed safely while electricity supply is maintained elsewhere where possible.
(ii) To help locate faults by enabling the system to be enlivened section by section.
(iii) To enable sections of load to be transferred from one feeder or supply source to another for

operational reasons.

1) Maintenance of Supply

When maintenance or other work requires the electricity to be cut off from a line section, air-break switches can be used to keep consumers elsewhere supplied. Consumers upstream of the air-break switch benefit from the fact that their supply need not be interrupted while maintenance is performed downstream of the switch. The benefit can therefore be quantified as the product of the installed transformer capacity upstream and the length of line downstream namely:

*Benefit= LCkVA*km*

Where: L the length of line downstream of the switch but not downstream of any other switch - km.
C the installed kVA upstream of the switch but not upstream of any other operational switchgear -kVA.

Note that in the case of a line section which can be fed from either end, the benefit is the sum of benefits calculated as above in each direction.

To justify the installation of an air-break switch in terms of (i) above, the benefit should be at least 10,000kVA- km.

Note that this figure is higher than it would be if the switch provided some form of automatic protection as is the case with dropout fuses.

2) Fault Location

The ability to sectionalize a line helps fault location, the benefit being a function of the length of line which can be isolated and the difficulty of access. In the case of D/Ls following roads, access is not a problem and it is sufficient to divide D/Ls into 10 - 15 km sections. Where vehicle access is not possible, section lengths may be reduced to as little as 5 km.

3) Interconnecting Air-Break Switches

Air-break switches are also used as interconnecting feeders for operational reasons and wIn such cases, the justification must be based on individual consideration. In some cases, interconnecting switches are used to maintain supply as discussed in (i) above, in which case the arguments used in that section can be applied.

Summarizing, the benefit required to justify the installation of an air-break switch in terms of maintenance of supply is 10,000kVA*km. Otherwise, to facilitate fault location, load break switches may be installed at 10-15 km intervals on reasonable roads, decreasing to as little as 5 km where access is particularly difficult.

Air-break switches may be fitted with flicker-type arcing contacts or load-break interrupter heads. Flicker contacts are limited to a breaking capacity of approximately 10 amps according to the load characteristics. Where routine switching of loads exceeding this is required, load break switches must be installed. As these are costlier than flicker contact switches, their installation should be fully justified by the load and frequency of use.

For simplification and to minimize store costs, 22kV air-break switches should be used on both 11 and 22kV lines, with the following minimum characteristics:

Table 2.2-4 Characteristics of Air-Break Switchers

	Flicker Contacts		Load Break Interrupters	
	11kV	22kV	11kV	22kV
Normal current (amp)	630	630	630	630
Short time current (kA)	20	20	20	20
Peak withstand current (kA)	50	50	50	50
BIL to earth (kV)	-	150	-	150
Load break capacity (amp)	10	10	400	400
Closed-loop break capacity (amp)	100	100	400	400
Magnetizing current breaking capacity (amp)	10	5	50	50
Line charging current breaking capacity (amp)	10	5	50	50

Source: Distribution Design Manuals, Part A Electrical design: Page A6.7, PPL

On radially interconnected systems, a maximum of only every second air-break switch requires load breaking capability, as parallels can be broken on a plain switch leaving only the load current of the section to be isolated to be interrupted by the second (load break) switch.

(5) Reclosers and Sectionalizers

The reasons for installing reclosers and sectionalizers are:

(i) To isolate faults which occur further out along the line, thereby maintaining supply to upstream consumers.
(ii) To limit damage at the point of any fault and restore supply for transient faults.
(iii) To help locate faults.
(iv) As switches.

Two pole overcurrents and one pole earth fault overcurrent relays constitute the main protection for outgoing H.V. feeders. These relays should coordinate with any 3-phase pole-mounted electronically controlled reclosers installed on feeders.

Reclosers may automatically reclose up to four times, hence the substation relay should be equipped with fast reset time characteristics.

Automatic sectionalizers are used in conjunction with reclosers but further out along the line to assist in isolating fault sections. To achieve discrimination between reclosers, sectionalizers and fuses, the following rules should be complied with:

(i) Reclosers can only be installed where the fault level is less than the rated interrupting capacity. 6.0 kA rated units can be employed on rural feeders.

(ii) Reclosers should not normally be operated in series.

(iii) Sectionalizers can usually only be used in conjunction with reclosers and must always be sited further out along the feeder. It may be possible to coordinate a sectionalizer with a substation circuit breaker equipped with auto-reclose relays.

(iv) No more than two sectionalizers should be operated in series but more than two can be used if they are on different branches of the same feeder.

When siting a recloser it is important to note that only those consumers upstream of a recloser benefit from the fact that they are unaffected by faults downstream of the recloser.

Accordingly, the product of the load upstream, measured in kVA of installed transformer capacity and the fault risk which can be represented by the length of line downstream, in kilometers, provides a measure of the benefit accruing from installing a recloser or sectionalizer. This benefit, in kVA*km, can be plotted along the length of a feeder to determine the optimum siting of a recloser and assess the justification for its use.

This can be expressed as:

$$B = LC$$

Where, B the benefit in kVA -km.
L the length of line which can be isolated by the recloser but not by any other protection device (sectionalizer or fuse) downstream - km.
C the installed transformer capacity upstream but not upstream of any further upstream protection device -kVA.

A figure can also be put on the benefit figure below, for which the installation of a recloser is not justified. Unfortunately, since most of the benefit is the value of an improved service to consumers, this minimum figure cannot be calculated. In the United Kingdom, minimum benefits of 20,000 to 50,000kVA*km are used. Taking the different situation in PNG into account, it is recommended that 20,000kVA*km be adopted as the minimum to justify the installation of a recloser.

The same argument as that used for reclosers applies to sectionalizers except that taking into account the lower cost of a sectionalizer, 18,000kVA*km is the appropriate minimum figure to justify the installation of a sectionalizer.

Reclosers and sectionalizers should be installed only where these minimum criteria can be met unless justified by exceptional operational requirements.

Reclosers and sectionalizers should have the following characteristics:

Table 2.2-5 Characteristics of Reclosers and Sectionalizers

Items	Value
Normal current	400 A
Short time (1 sec) current	6 / 10 KA
Peak making current	15 kA

The control devices and operating characteristics should be chosen to coordinate correctly with downstream dropout fuse links and upstream protective relays.

Summarizing, the benefit to justify the installation of reclosers and sectionalizers, in terms of fault clearance and maintenance of supply is:

Reclosers	20,000kVA*km
Sectionalizers	18,000kVA*km

(6) Dropout Fuses

Dropout fuses are used on spur lines for the following reasons:

(i) To isolate any fault which may occur on the spur, thereby maintaining an uninterrupted supply to upstream consumers.
(ii) To isolate a spur for maintenance and other work to be performed without cutting the electricity supply elsewhere.

(iii) To help locate faults by enabling the spur to be isolated and flagging any fault that does occur.
(iv) Dropout fuses are used to provide group fusing.

Note that dropout fuses cannot be relied on to provide back-up overload protection for distribution transformers.

Operating one of a set of dropout fuses may damage 3-phase motors unless appropriate protective devices are provided.

1) Maintenance of Supply

Dropout fuses benefit consumers upstream, similar to reclosers and sectionalizers. However, an additional factor is that for fuses, supply is not swiftly restored when an operation is caused by a current surge, even though no damage results. The ratio of non-damage to damage fuse operations varies according to the circumstances influencing individual lines. A line threatened by trees, for example will have a lower ratio than one which traverses open country.

For a study as wide as this, we can assume a ratio of 1, i.e. that 50% of fuse operations result from non-damage events.

The equation is:

$$\underline{Benefit = L\ [kYA_f - (f + 1)kVA_s]kVA*km}$$

Where, L the length of the spur in km.
kVA_f the transformer capacity on the feeder and the spur but excluding any capacity upstream of an upstream protection device.
kVA_s the transformer capacity on the spur.
F the ratio of non-damage to damage fuse operations.

To justify the cost of the installation, above grounds, the benefit should be no less than 4,000kVA*km.

2) Group Fusing

Group fusing is the use of a single set of fuses on a spur instead of separate fuses on each transformer station along a spur and helps save costs with minimal decline in reliability. The concept is limited by the need for fuses to discriminate with upstream protection facilities and the fact that the resulting inconvenience may not be acceptable where large communities and industrial loads are involved.

It is therefore recommended that group fusing of spurs only be used where:

(i) None of the transformers on the spur exceed 100kVA.
(ii) The total transformer capacity on the spur does not exceed 750kVA.

Summarizing, the benefit required to justify the installation of dropout fuses, in terms of fault clearance and maintenance of supply, is 4,000kVA*km. Dropout fuses can also be used in place of substation fuses on a group fusing basis, but only to protect branch lines with an installed transformer capacity of less than 750kVA and with no individual transformers exceeding 100kVA.

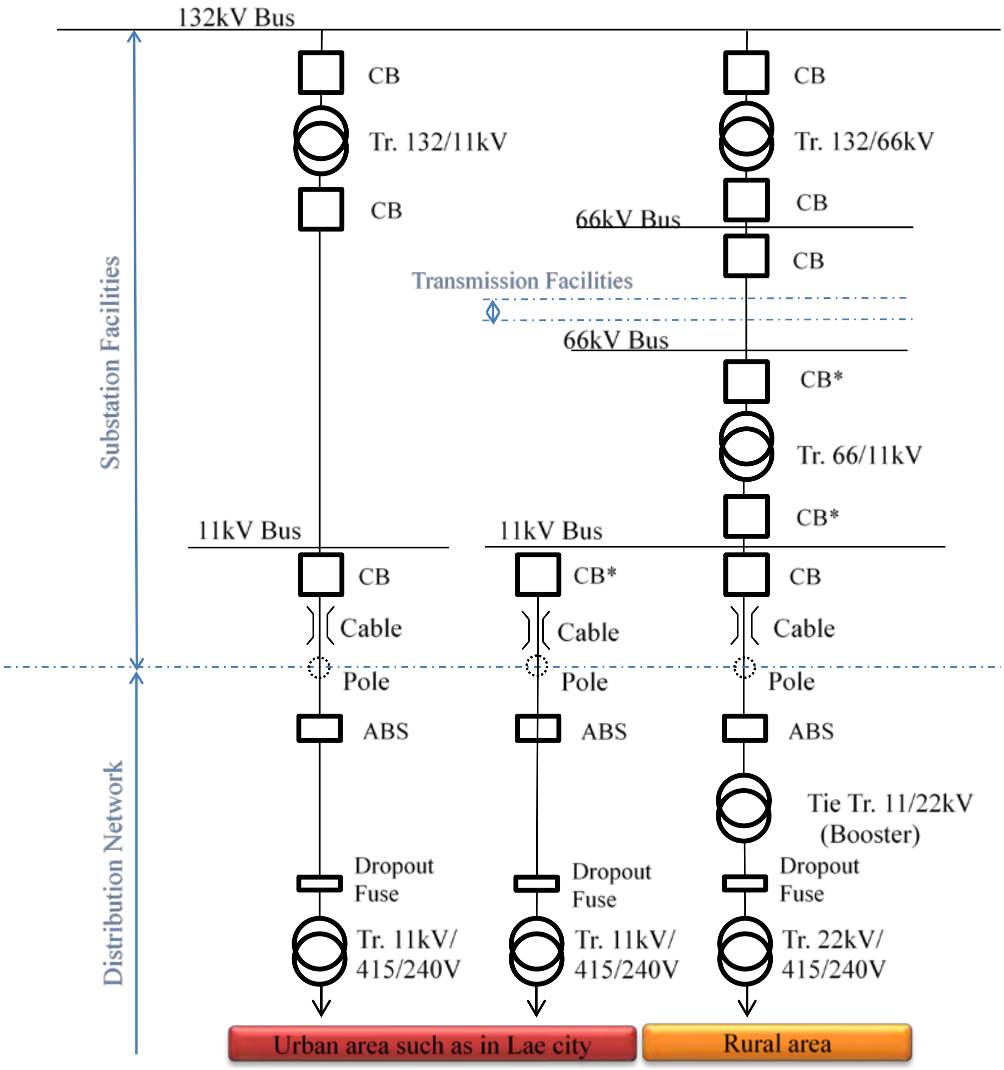
2.3 DISTRIBUTION NETWORK FACILITIES IN THE LAE AREA

The current status of the major types of the distribution network facilities in the Lae area may be summarized as follows:

2.3.1 Distribution Network

(1) Voltage classes

The basic configuration of the distribution network in the Lae area is shown in Fig. 2.3-1.



Note: CBs are not installed at the Nadzab substation.

Fig. 2.3-1 Basic Configuration of the Lae Distribution Network

The distribution network comprises 3-phase, three-wire 22 and 11kV high-voltage system and 3-phase, four-wire 415 and 240V low-voltage system. Much of the area supplied by PPL is urban area such as Lae city and has a high load density that operated at 11kV. In other hand, the rural area has low load density that tends to lengthen the D/L length.

For this reason, much of the D/Ls in rural area are operated at 22kV, to reduce losses.

Voltage classes in standard used in the Lae area is shown in Table 2.3-1.

Table 2.3-1 Voltage Class

Nominal system voltage	Maximum system voltage	Remarks
22kV	24kV	Much of rural area
11kV	11kV	All of the Lae city and some of the rural area.

(2) Single-line diagram and Geographic operating diagram

System information on H.V. distribution network constitutes basic data for planning the improvement of the distribution facilities and for facility operation and maintenance. Its compilation is therefore crucial.

Single-line diagrams are used to manage this information, but utilities also need map information (geographic operating diagram) for distribution networks, which cover a wide area. Knowledge of the D/L types and distances as well as the location and capacity of distribution substations from a single-line diagram enables rough calculation of the power flow to obtain current and voltage drop values. This information is essential to consider planning of expansion and facility management. However, failure to reflect system information on maps can cause inconvenience regarding information for distribution planning and proper (quick and safe) system operation after D/L faults. (At present, the distribution team leaders of the workshop basically only remember the information, for example, which equipment such as switches and transformers of which lines are in which area and rely on this memory when entering the field.) Accordingly, it is preferable to possess both single-line diagrams and geographic operating diagram to maintain and manage distribution networks.

1) Single-line diagrams

Distribution network have a broad physical extension and it is crucial to manage (as charts) accurate data for 11/22kV D/Ls, not only for maintenance but also all other distribution work. At present, PPL Lae prepare (with AutoCAD and other tools) and manage single-line diagrams for 11/22kV distribution networks. Nevertheless, the following issues have also surfaced and reflect the need for improved management.

(a) Sure reflection about feeder extension information

The diagrams must indicate accurate information on the line situation at all times, because this information is necessary for facility management and planning for expansion. From now on, the utilities must make it a rule to add such information to the diagrams each time to extend the H.V. distribution network.

(b) Length information discrepancies

In some cases, significant discrepancies exist between the distance shown on the single-line diagrams and the actual distance. Similarly, some diagrams do not show the type of line or have a wrong indication of type. When patrolling D/Ls, it is important to check whether the diagram information differs from the actual distribution facilities. If discrepancies are found, it is similarly vital to make prompt revisions and ensure the information managed on diagrams is accurate.

(c) Prompt updating of information

When high-voltage lines are reinforced or extended, the results are sometimes not added to single-wire diagrams. Proper information management demands prompt updating of diagrams when facilities are replaced.

2) Map information (Geographic operating diagram) for distribution lines

At PPL Lae, no updated map information has been established for H.V. lines for 10 years or more. Such information is crucial, not only when studying plans to reinforce and extend facilities but also for facility maintenance. For example, it assists when specifying locations for patrols of complex D/Ls and in the event of reported trouble with facilities. In light of the needs associated with management and updating, it would be more efficient to manage this kind of information in the form of electronic data.

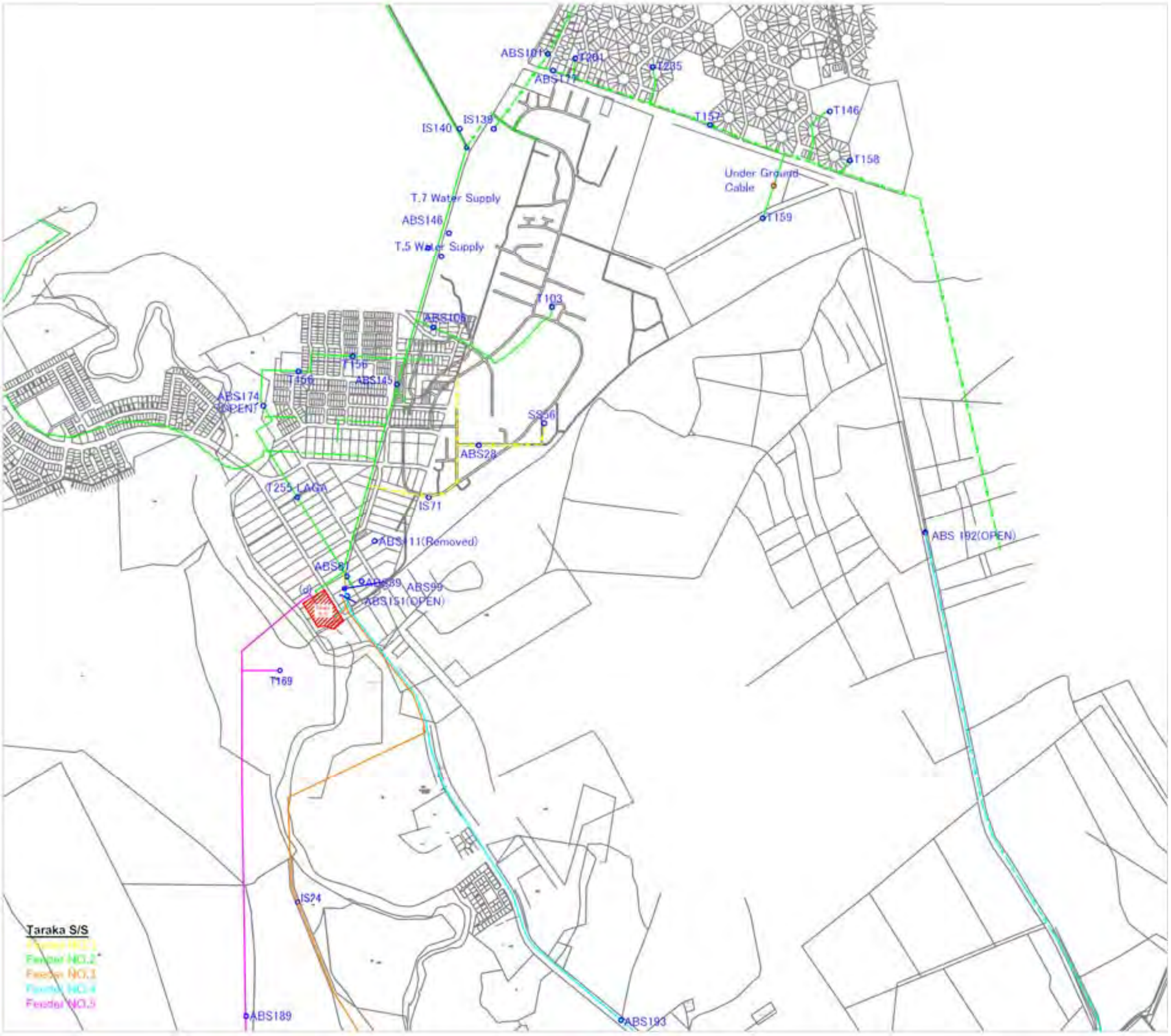
In this study, a serious mismatch between the geographic information (drawings) and actual equipment were confirmed following the result of the first field survey conducted in November - December 2014.

In response, based on stringent drawing management, JICA Study Team prepared new geographic information (CAD drawings) in Lae and PPL Lae provided additional distribution network equipment information.

Thanks to collaboration between JICA Study Team and PPL Lae, the single-line diagram and H.V. Geographic operating diagram were updated as of March 2015.

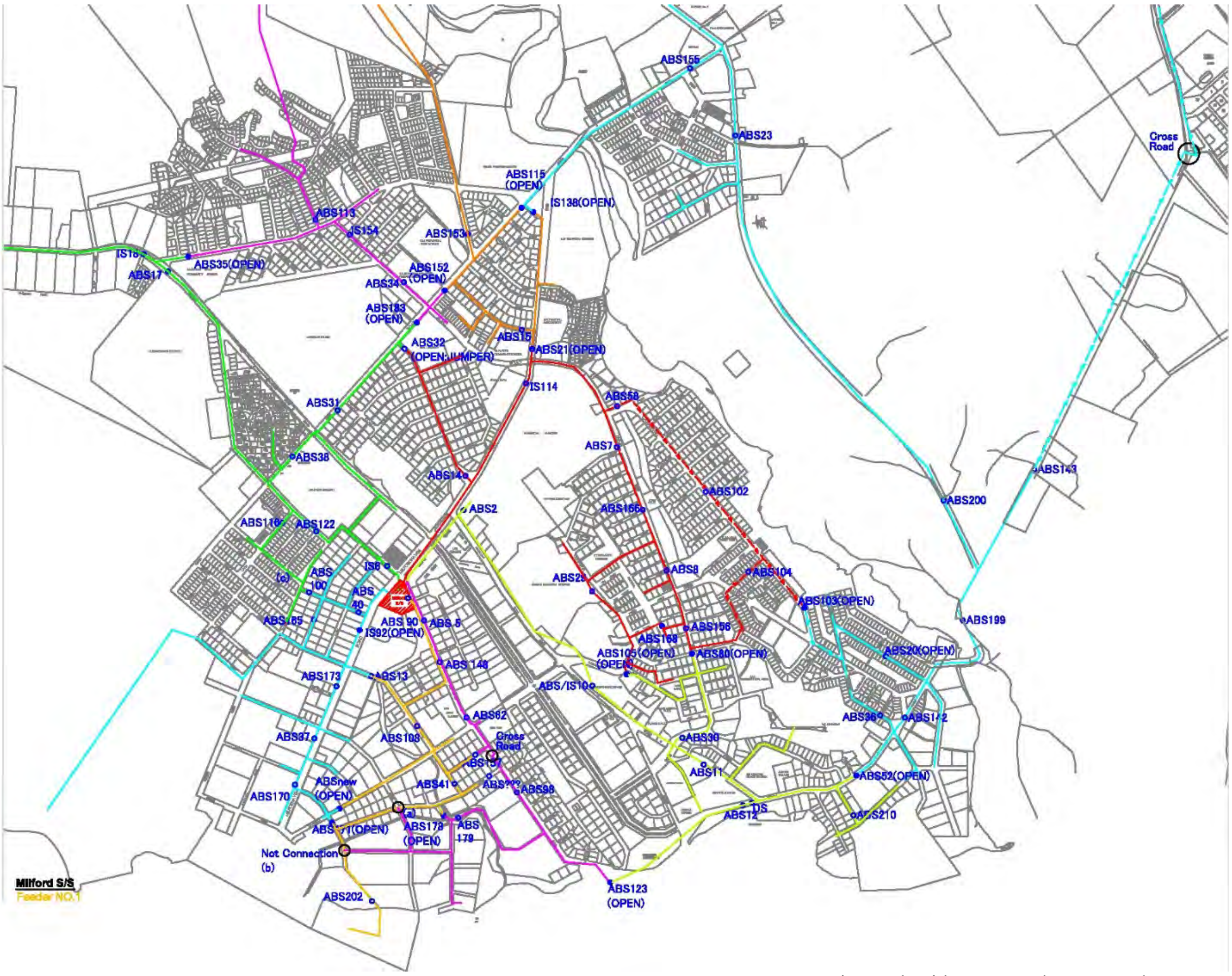
Single-line diagram shown in Fig. 2.3-4 and Fig. 2.3-5. The H.V. Geographic operating diagram in urban area is shown in Fig. 2.3-2 and Fig. 2.3-3. The H.V. Geographic operating diagram in rural area is shown in Appendix B-1.

For reference, a single-line diagram provided by PPL Lae is shown in Appendix B-2 and a geographic operating diagram as of year 2000 is shown in Appendix B-3.



Source: Joint work with JICA Study Team and PPL Lae

Fig. 2.3-2 H.V. Geographic Operating Diagram in Lae (1)



Source: Joint work with JICA Study Team and PPL Lae

Fig. 2.3-3 H.V. Geographic Operating Diagram in Lae (2)

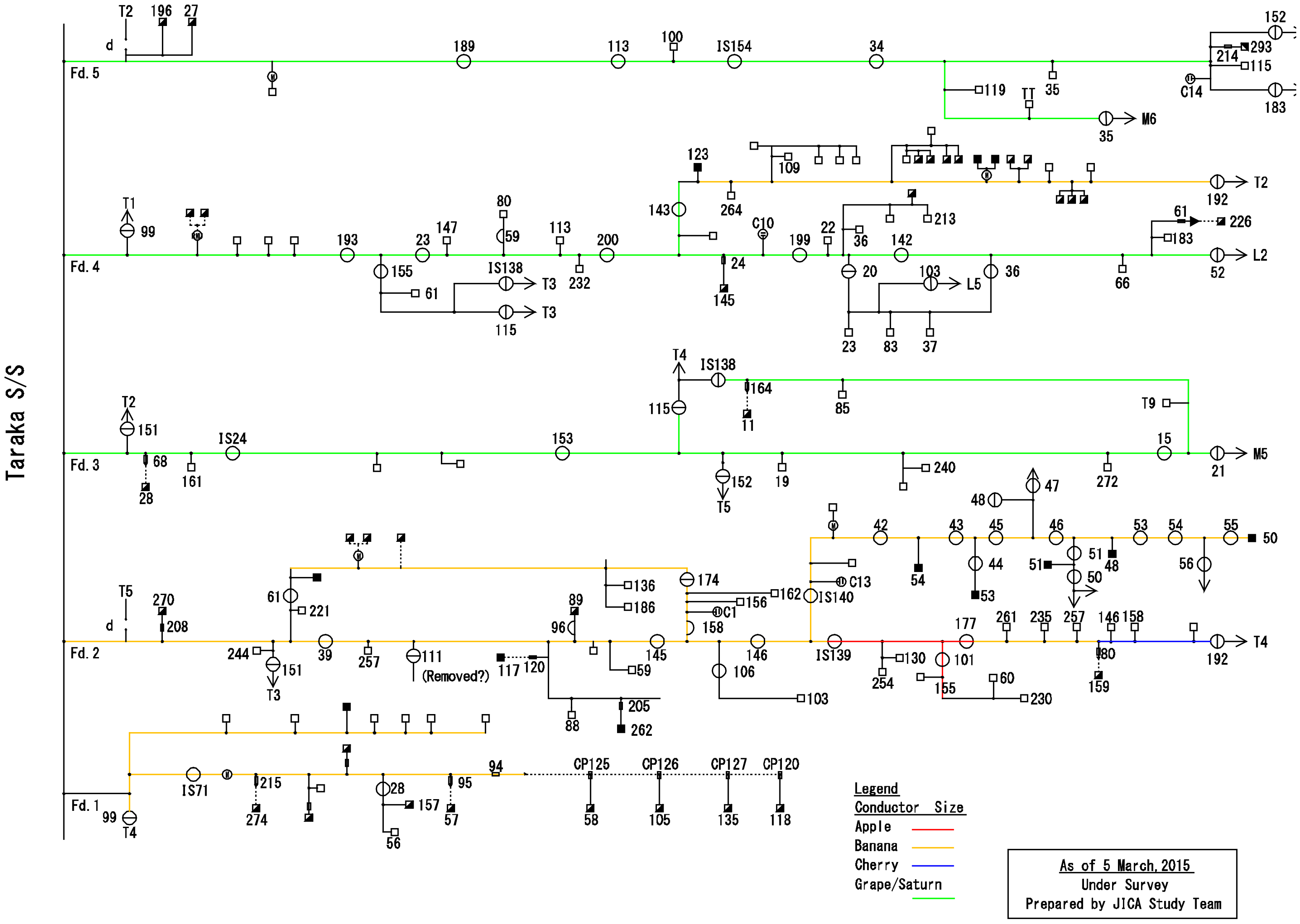


Fig. 2.3-4 Single Line Diagram on Distribution Network (1)

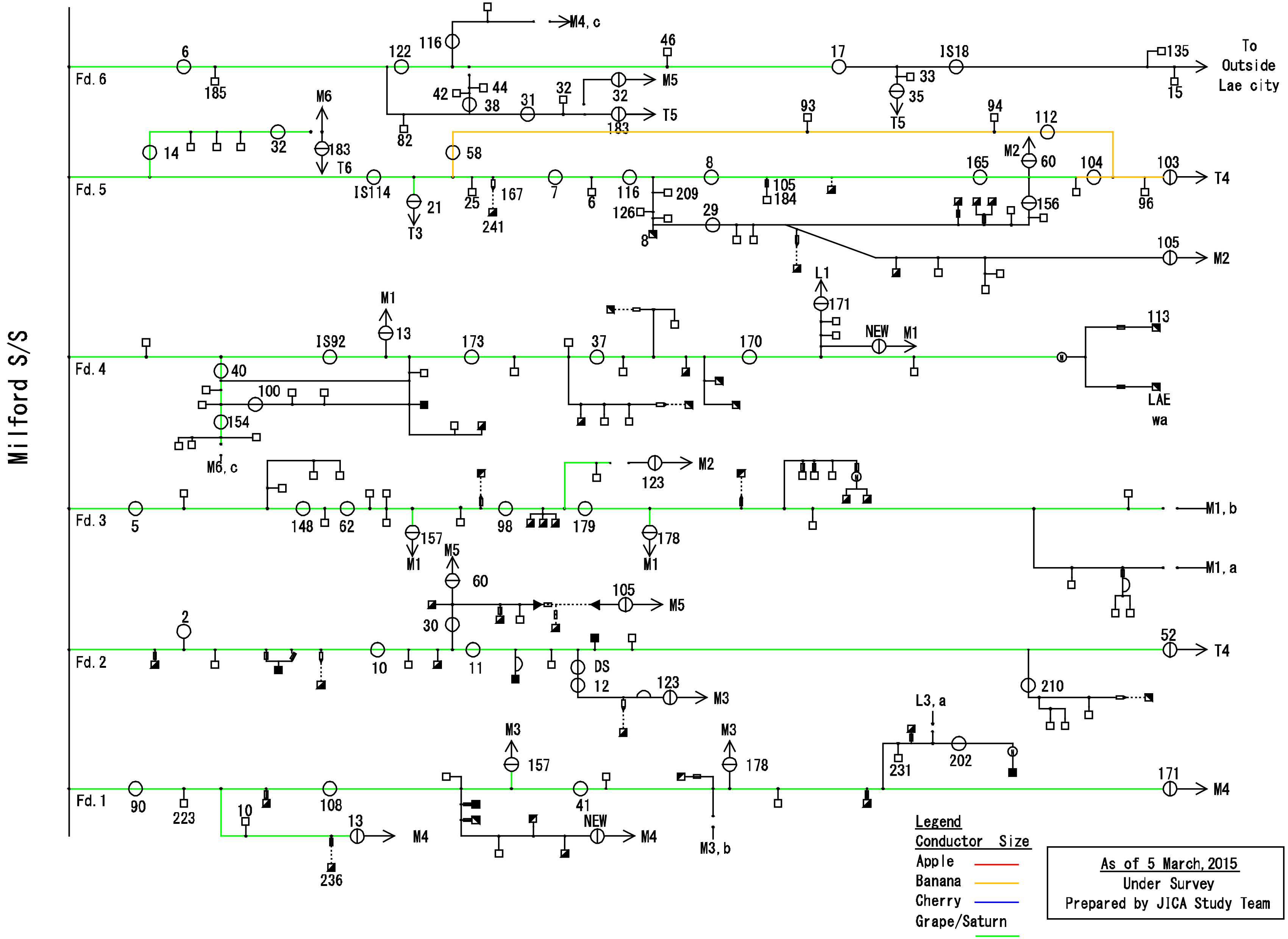


Fig. 2.3-5 Single Line Diagram on Distribution Network (2)

2.3.2 Conductor

D/Ls in the Lae area can be divided into the following two categories:

- Overhead lines
- Underground cables

The main conductors used for overhead lines are Aluminum Standard Conductors Galvanized steel-reinforced (ASCR/GZ). The main size [codes] are 182 [Grape], 120 [Cherry], 77.3 [Banana] and 49.5 [Apple] square millimeters (mm^2) in urban areas and 120 [Cherry] in rural areas.

All-aluminum conductors (AAC), made of bare aluminum, are the main types used for part of the high-load density area.

Physical and Mechanical Performance Data of conductor and Electrical Performance Data of conductor in the standard used for D/Ls in the Lae area are shown in Table 2.3-2 and Table 2.3-3.

Moreover, the length of the distribution networks in the Lae area is shown in Table 2.3-4 and a breakdown of the lengths of the distribution network in Appendix B-4.

Table 2.3-2 Physical and Mechanical Performance Data of Conductor

Type (Bare Conductors)	Conductor Codename	Stranding and wire diameter (no./mm)		Nominal overall diameter (mm)	Cross-sectional area (mm^2)	Approximate mass (kg/km)
		Aluminum	Steel			
ACSR/GZ	Apple	6/3.00	1/3.00	9	49.5	171
	Banana	6/3.75	1/3.75	11.3	77.3	268
	Cherry	6/4.75	7/1.60	14.3	120	402
	Grape	30/2.50	7/2.50	17.5	182	677
AAC	Saturn	37/3.00	-		262	721

Source: Olex catalog

Table 2.3-3 Electrical Performance Data of Conductor

Type (Bare Conductors)	Conductor Codename	DC Resist. At 20°C Ω/km	DC Resist. At 50Hz 75°C Ω/km	Continuous current carrying capacity (A)
ACSR/GZ	Apple	0.677	0.910	248
	Banana	0.433	0.582	326
	Cherry	0.271	0.367	434
	Grape	0.196	0.263	531
AAC	Saturn	0.110	0.135	776

*: 2m/s wind, Rural weather, summer noon

Source: Olex catalog

Table 2.3-4 Length of the Distribution Network in the Lae Area

(Unit: m)

		11kV			22kV			Total
		Urban area	Rural area	Sub Total	Urban area	Rural area	Sub Total	
Taraka S/S [In Lae city]								
	Feeder No. 1	3,972	0	3,972	0	0	0	3,972
	Feeder No. 2	18,160	0	18,160	0	0	0	18,160
	Feeder No. 3	6,478	0	6,478	0	0	0	6,478
	Feeder No. 4	17,361	0	17,361	0	0	0	17,361
	Feeder No. 5	6,127	0	6,127	0	0	0	6,127
	Subtotal	52,098	0	52,098	0	0	0	52,098
Milford S/S [In Lae city]								
	Feeder No. 1	4,787	0	4,787	0	0	0	4,787
	Feeder No. 2	6,876	0	6,876	0	0	0	6,876
	Feeder No. 3	3,999	0	3,999	0	0	0	3,999
	Feeder No. 4	6,067	0	6,067	0	0	0	6,067
	Feeder No. 5	8,157	0	8,157	0	0	0	8,157
	Feeder No. 6	9,979	2,390	12,369	0	3,460	3,460	15,829
	Subtotal	39,865	2,390	42,255	0	3,460	3,460	45,715
Nadzab S/S [Outside Lae city]								
	Feeder No. 1	0	6,100	6,100	0	85,000	85,000	91,100
	Subtotal	0	6,100	6,100	0	85,000	85,000	91,100
Total		**91,963**	**8,490**	**100,453**	**0**	**88,460**	**88,460**	**188,913**

2.3.3 Supporting Structures

In the urban area, the main type of supporting structure for overhead lines is a steel pole with wooden cross-arms, while a wooden pole and steel cross-arms are installed in part of the urban area.

In rural areas, there is extensive use of the combination of steel poles with wooden cross-arms, but some concrete poles and wooden poles also installed.

The span indicating the interval between supporting structures is within the range 120 - 150 m in some urban areas, but ranges from 150 m in rural areas. The span depends on the physical and mechanical performance of the conductor and its tensile strength.

Fig. 2.3-6 Photographs of Pole

2.3.4 Insulators

The standard types of insulator are pin, post and suspension. Utilities utilize pin insulators for straight-line sections, post insulators for sloping/straight sections and suspension insulators at anchor points.

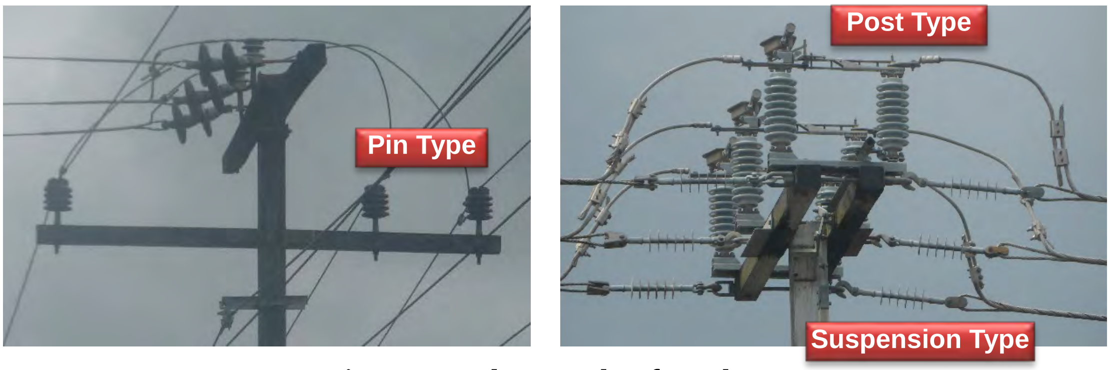


Fig. 2.3-7 Photographs of Insulators

2.3.5 Distribution Switchgears

Switching, sectionalizing and isolating on the H.V. distribution network is conducted via outdoor pole top-mounted air-break switches. Dropout fuses are also installed for protective isolating. Spurs one sectionalizer is installed at boundary on west side Lei city.

The Lae area contains three standard types of switchgears: Air-Break Switches, Dropout Fuses and Sectionalizers. An outline of standard switches is shown in Table 2.3-5.

Table 2.3-5 Outline of Standard Switches

Switchgear Type	Outline
Air-Break Switches	✓ To isolate parts of the system so that maintenance and other work can be performed safely while the electricity supply is maintained elsewhere where possible. ✓ To help locate faults by enabling the system to be relieved section by section. ✓ To enable load sections to be transferred from one feeder or supply source to another for operational reasons.
Dropout Fuses	✓ To isolate any fault which may occur on the spur, thereby maintaining an uninterrupted supply to upstream consumers. ✓ To isolate a spur for maintenance and other work to be performed without cutting the electricity supply elsewhere. ✓ To help locate faults by enabling the spur to be isolated and flagging any fault that does occur. ✓ Dropout fuses are used to provide group fusing.
Sectionalizer	✓ To isolate faults which occur further out along the line thereby maintaining supply to upstream consumers. ✓ To limit damage at the point of any fault and restore supply for transient faults. ✓ To help locate faults.

(1) Air-Break Switches (ABS)

103 units of ABS are installed in Lae city. However, 25% of ABS have some problems for the following reasons:

ABS/IS rated at 100 A have been burnt out.
Bypassed/bridged ABS limits the ability to switch and transfer loads.

The ABS condition in the Lae area is shown in Fig. 2.3-9 and Fig. 2.3-10. A list of ABS in Lae city is shown in Table 2.3-6 and Table 2.3-7.

PPL Lae attempts to repair broken ABSs as part of routine work. However, increased loads along D/Ls are hindering switching.

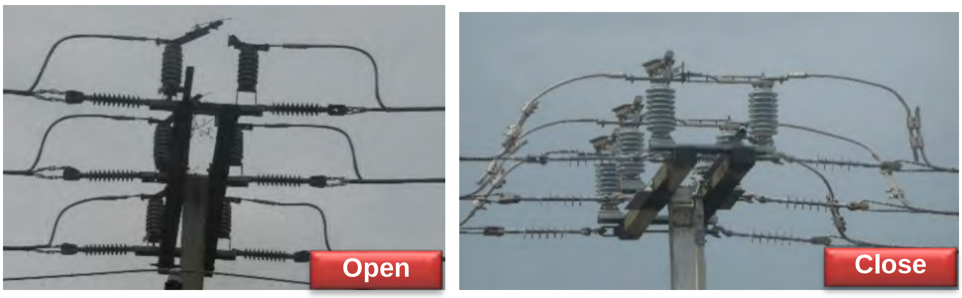


Fig. 2.3-8 Photographs of Air-Break Switches

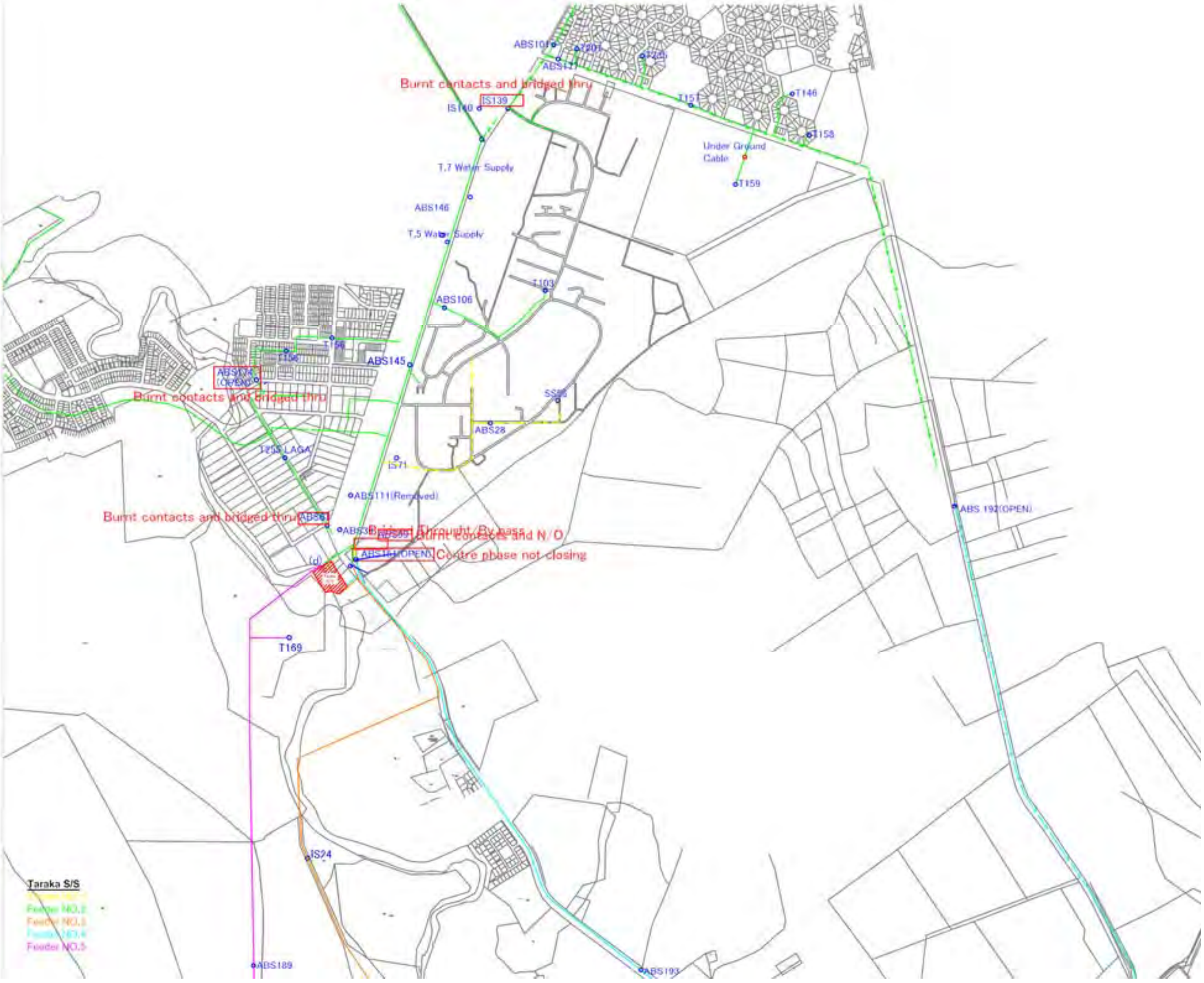


Fig. 2.3-9 H.V. Geographic Operating Diagram with Air-Break Switches (1)

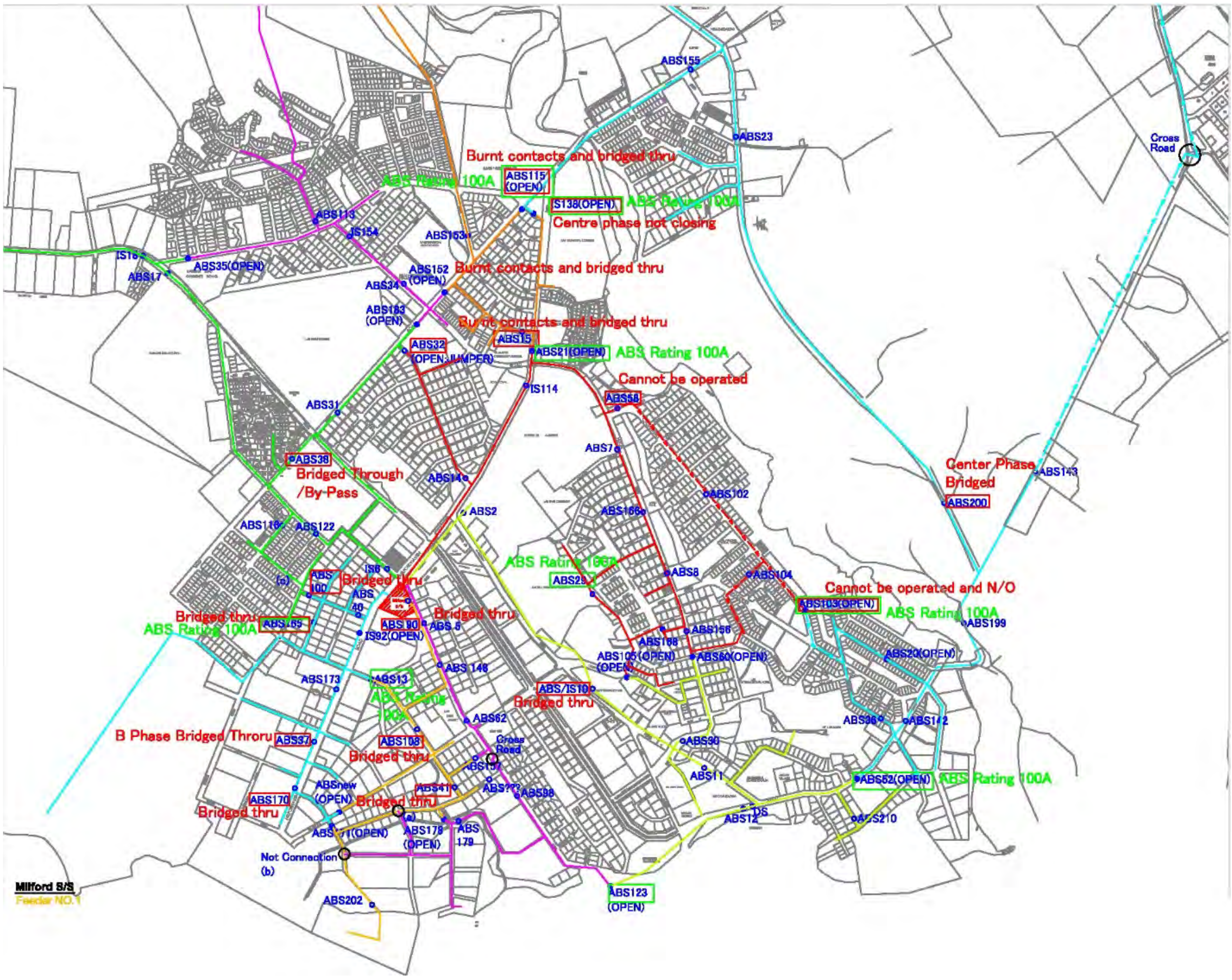


Fig. 2.3-10 H.V. Geographic Operating Diagram with Air-Break Switches (2)

Table 2.3-6 List of ABS (1)

Fdr ID	Switch Gear	Defect	Close/ Open	Defect/ Operatinal	Location	Remrks	Capacity
Milford 1	**ABS 90**	#	Close	Defect	Milford Power House	Bridged Through/By Pass	
	ABS 108	#	Close	Defect	Ela Motors Card Yard	Bridged Through/By Pass	
	ABS 41	#	Close	Defect	Bishop Brothers	Bridged Through/By Pass	
	ABS 202		Close	Operational	PNG Taiheiyo Cement		
Milford 2	**ABS/IS 10**	#	Close	Defect	Air Niugini Sales Office	Bridged Through/By Pass	
	ABS 30		Close	Operational	Mountain Top Huon Road		
	ABS 11		Close	Operational	Stadium Residential Area		
	ABS 12		Close	Operational	Indoor Stadium		
	ABS 210		Close	Operational	UMW		
	ABS2		Close				
Milford 3	**ABS 5**		Close	Operational	Dunlop		
	ABS 148		Close	Operational	Mainland Plumbing		
	ABS 62		Close	Operational	Agmark Machinery		
	ABS 98		Close	Operational	SP Brewery Gate		
	ABS 179		Close	Operational	Opposite Flour Mill		
Milford 4	**ABS 40**		Close	Operational	Chemica		
	ABS 100	#	Close	Defect	Mula Street	Bridged Through/By Pass	
	IS 92		Close	Operational	Ela Motors Sales Office		
	ABS 173		Close	Operational	Hastings Deering	Bridged Through/By Pass (Operated on Feb.2015)	
	ABS 37	#	Close	Defect	Atlas Steel	B Phase Bridged Through	
	ABS 170	#	Close	Defect	Coca Cola	Bridged Through/By Pass	
	ABS 154	#	Close	Defect	Tolec Electronic	Cannot be operated-N/C	Rating 100A
Milford 5	**ABS 14**		Close	Operational	Fire Service Station		
	IS 114		Close	Operational	Eriku Soccer Field		
	ABS 58	#	Close	Defect	Cassowary/Huon Road Junctgion	Cannot be operated	
	ABS 7		Close	Operational	FRI		
	ABS 166		Close	Operational	8th Street		
	ABS 8		Close	Operational	11th Street		
	ABS 165		Close	Operational			
	ABS 156		Open	Operational	5th Street		
	ABS 29		Close	Operational	Angau Sisters Quarter		Rating 100A
	ABS 102		Close	Operational	Eagle Street		
	ABS 104		Close	Operational	Tern Street		
Milford 6	**IS 6**		Close	Operational	Hospital Area Stores		
	ABS 116		Close	Operational	Jawani Street		
	ABS 38	#	Close	Defect	Show Ground/Salamanda	Bridged Through/By Pass	
	ABS 31		Close	Operational	Opposite Golf		
	ABS 17		Close	Operational	Bugandi Secondary School		
	ABS 122		Close	Operational			
	ABS 18		Close	Operational	Two Mile		
Taraka 1	**IS 71**		Close	Operational	Unitech		
	ABS 28		Close	Operational	Unitech		
Taraka 2	**ABS 39**	#	Close	Defect	Atlas Steel	Bridged Through/By Pass	
	ABS 61	#	Close	Defect	NCI	Bridged Through/By Pass	
	ABS 145		Close	Operational	Interoil		
	ABS 106		Close	Operational	Unitech Residential Area		
	ABS 146		Close	Operational	Opposite Water No. 4		
	ABS 174	#	Open	Defect	East Taraka Housing	Faulty-N/O	
	IS 139	#	Close	Defect	Igam Juction	Bridged Through/By Pass	
	IS 140		Close	Operational	Igam Juction		
	ABS 177		Close	Operational	PTC Junction		
	ABS 101		Close	Operational	Bumayong Junction		
	ABS 42		Close	Operational	Igam Barracks		
	ABS 43		Close	Operational	Igam Barracks		
	ABS 44		Close	Operational	Igam Barracks		
	ABS 45		Close	Operational	Igam Barracks		
	ABS 47		Close	Operational	Igam Barracks		

Table 2.3-7 List of ABS (2)

Fdr ID	Switch Gear	Defect	Close/ Open	Defect/ Operatinal	Location	Remrks	Capacity
	ABS 46		Close	Operational	Igam Barracks		
	ABS 50		Close	Operational	Igam Barracks		
	ABS 51		Open	Operational	Igam Barracks		
	ABS 53		Close	Operational	Igam Barracks		
	ABS 54		Close	Operational	Igam Barracks		
	ABS 55		Close	Operational	Igam Barracks		
	ABS 56		Close	Operational	Igam Barracks		
Taraka 3	**IS 24**		Close	Operational	Timber College		
	ABS 153		Close	Operational	Buimo Road Junction		
	ABS 15	#	Close	Defect	Gurney Street	Bridged Through/By Pass	
Taraka 4	**ABS 193**		Close	Operational	Kamkumung Ples		
	ABS 155		Close	Operational	Omili Primary School		
	ABS 23		Close	Operational	Awagasi Market		
	ABS 200	#	Close	Defect	Butibum Village	Centre Phase Bridged Thruogh	
	ABS 199		Close	Operational	Bumbu Bridge		
	ABS 142		Close	Operational	China Town		
	ABS 36		Close	Operational	Opposite Nestle		
	ABS 20		Open	Operational	Bowerbird Street		
	ABS 143		Close	Operational	Balop Teachers'College		
Taraka 5	**ABS 189**		Close	Operational	Abattoir		
	ABS 113		Close	Operational	Mountain Cress	Replaceed on Feb. 2015	
	IS 154		Close	Operational	Boundary Road		
	ABS 34		Close	Operational	Lae Primary School		
raka 1 & Taraka	**ABS 99**	#	Open	Defect	Shell Service Station	Burnt Contacts-N/O	
raka 2 & Taraka	**ABS 192**		Open	Operational?	Back Road		
raka 2 & Taraka	**ABS 151**	#	Open	Defect	Cummins		
raka 3 & Taraka	**ABS 152**		Open	Operational?	Phils Motel		
raka 3 & Taraka	**ABS 115**	#	Open	Defect	Our Saviour Church		Rating 100A
raka 3 & Taraka	**IS 138**	#	Open	Defect	Cross Street		Rating 100A
raka 3 & Milfor	**ABS 21**		Open	Operational?	St Michael's Church		Rating 100A
lford 2 & Tarak	**ABS 52**		Open	Operational?	Nestle		Rating 100A
raka 5 & Milfor	**ABS 183**		Open	Operational?	Highlands Bus Stop Eriku		
raka 5 & Milfor	**ABS 35**		Open	Operational?	212 Estate		
lford 1 & Milfor	**ABS 157**		Open	Operational?	Brian Bell Service Parts		
lford 1 & Milfor	**ABS 178**		Open	Operational?	Flour Mill		
lford 1 & Milfor	**ABS 171**		Open	Operational?	SVS Whare House		
lford 1 & Milfor	**ABS (New)**		Open	Operational?	Papindo Whare House		
lford 2 & Milfor	**ABS 60**		Open	Operational?	Huon Road Town		
lford 2 & Milfor	**ABS 105**		Open	Operational?	St Mary's Church town		
lford 2 & Milfor	**ABS 123**		Open	Operational?	DCA Compound		Rating 100A
lford 1 & Milfor	**ABS 13**		Open	Operational?	Works Dept Compound		Rating 100A
lford 5 & Milfor	**ABS 32**	#	Open	Defect	Kwila/Bumbu Road Junct	Cannot be operated-N/O	
raka 4 & Milfor	**ABS 103**	#	Open	Defect	Cassowary Road	Cannot be operated-N/O	Rating 100A
raka 2 & Taraka	**ABS 151**	#	Open	Defect	Cummins	Centre Phase Faulty/By Pass	

(2) Sectionalizer

One sectionalizer was installed at the west side of Lae city in 2015. This switch is to sectionalize the 11kV D/L No. 6 from Milford S/S into urban and rural areas.

The sectionalizer is located approximately 10km west of Lae city.

Fig. 2.3-11 Location of Sectionalizer

Fig. 2.3-12 Photographs of Sectionalizer

2.3.6 Transformer

(1) Tie transformers

Two (2) tie transformers are installed outside Lae city. One tie transformer which converts voltage to 22kV from 11kV is installed on feeder No. 6 from Milford S/S. The other is installed on feeder No. 1 from Nadzab S/S.

The key specification is shown in Table 2.3-8. The location and photographs of tie transformers are shown in Fig. 2.3-13 and Fig. 2.3-14.

Table 2.3-8 Key Specification of the Tie Transformer

Item	Tie transformer 1	Tie transformer 2
Rated Capacity	4,000kVA	1,000kVA
Rated Voltage	22kV/11kV	22kV/11kV
Frequency/Type	50Hz/Three-phase	50Hz/Three-phase
Service Conditions	Outdoor	Outdoor
Manufacturing year/Country	2003/Australia	-

Source: JICA Study Team

Source: JICA Study Team

Fig. 2.3-13 Location of the Tie Transformers

Fig. 2.3-14 Photographs of the Tie Transformers

(2) Distribution transformers

Distribution transformers are connected to H.V. D/Ls in a T-branch and protected by lightning arresters in parallel and cutout fuses in series.

In the Lae area, there are three standard types of distribution transformers: Pole-mounted, Pad-mounted and Kiosk. Transformers with capacities of 10, 25, 50, 100, 200, 300, 500, 750 or 1,000kVA are in widespread use. An outline of standard transformers is shown in Table 2.3-9.

Regarding the neutral grounding system for transformers, a DyN-type solid grounding system is applied.

The distribution transformer list provided from PPL Lae is attached as Appendix B-5. However, this list is being reviewed by PPL Lae.

Table 2.3-9 Outline of Standard Distribution Transformers

Primary Voltage	Type	Size (kVA)
22kV	Pole-mounted	10, 25, 50, 100, 200
11kV	Pole-mounted	25, 50, 100, 200, 315, 500
	Pad-mounted	200, 300, 500, 750, 1000
	Kiosk	200, 300, 500, 750, 1000

Source: PPL

Kiosk Type

Pole-mounted Type

Fig. 2.3-15 Photographs of Distribution Transformers

2.3.7 Lightning Arresters

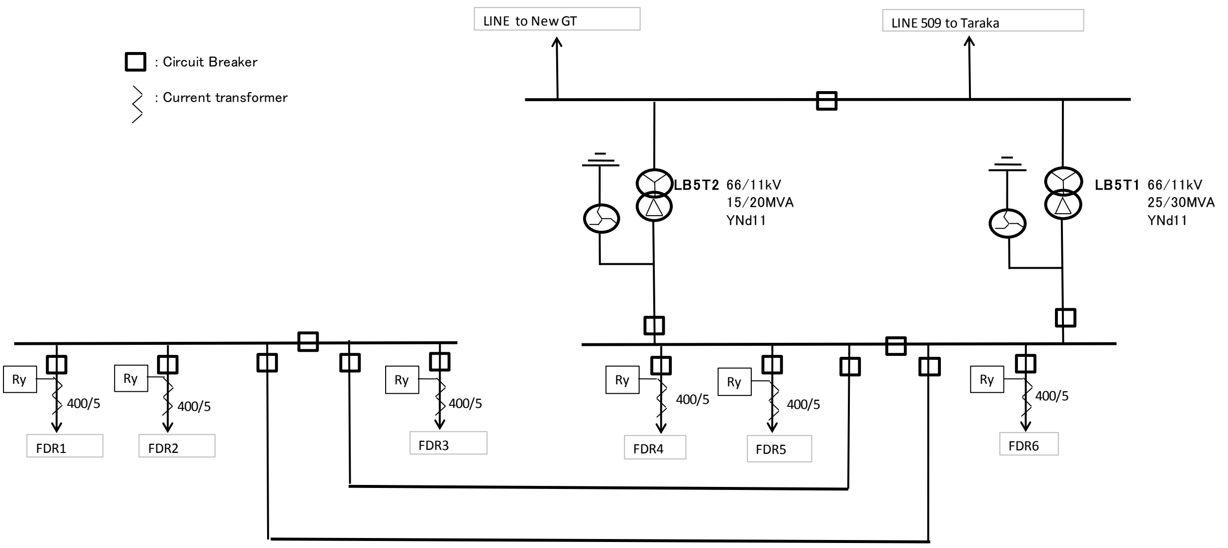
Lightning arresters are installed at terminals of distribution transformers and cable connected overhead lines. They are seemingly not installed to protect D/L and switchgears.

2.3.8 Protection Relay

(1) Outline of the Distribution Protection Relay

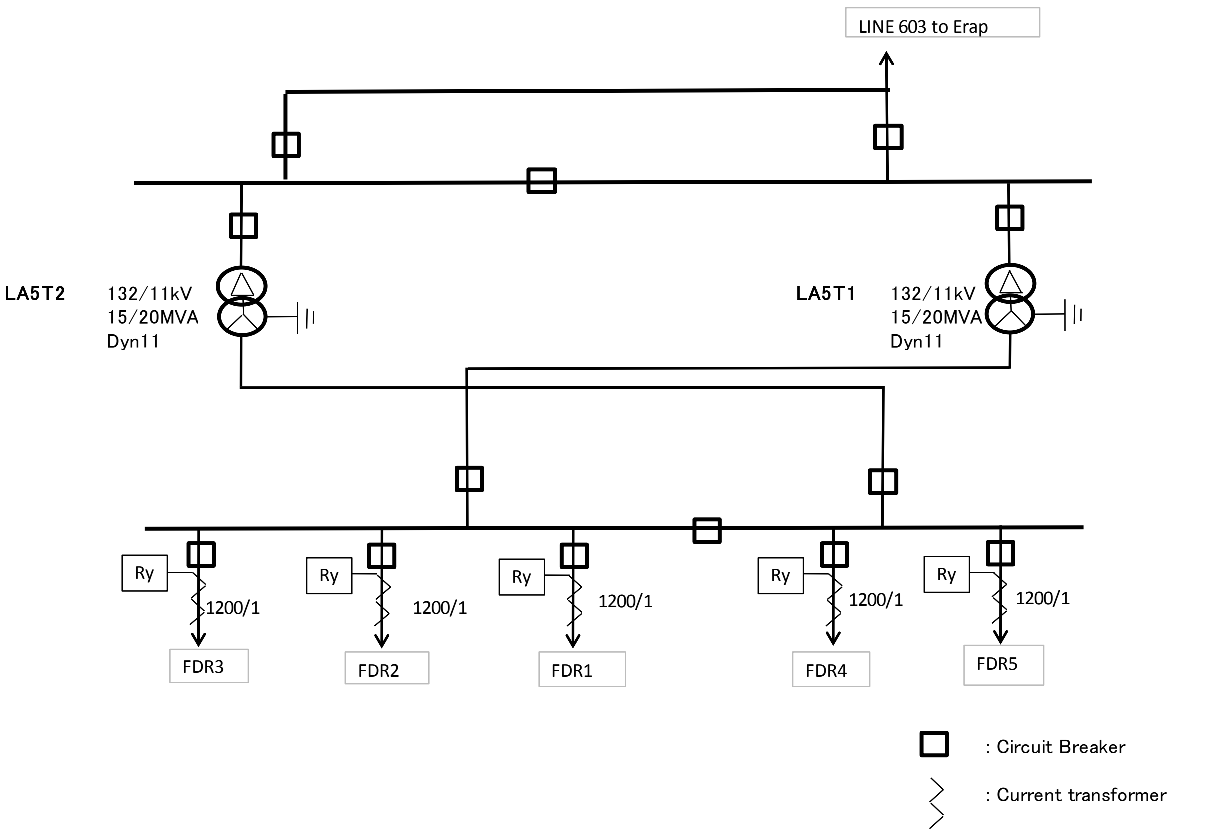
There are six feeders in Milford S/S, five feeders in Taraka S/S and one feeder in Nadzab S/S in the Lae area.

Fig. 2.3-16 - Fig. 2.3-18 show 11kV single-line diagrams in Milford S/S, Taraka S/S and Nadzab S/S.



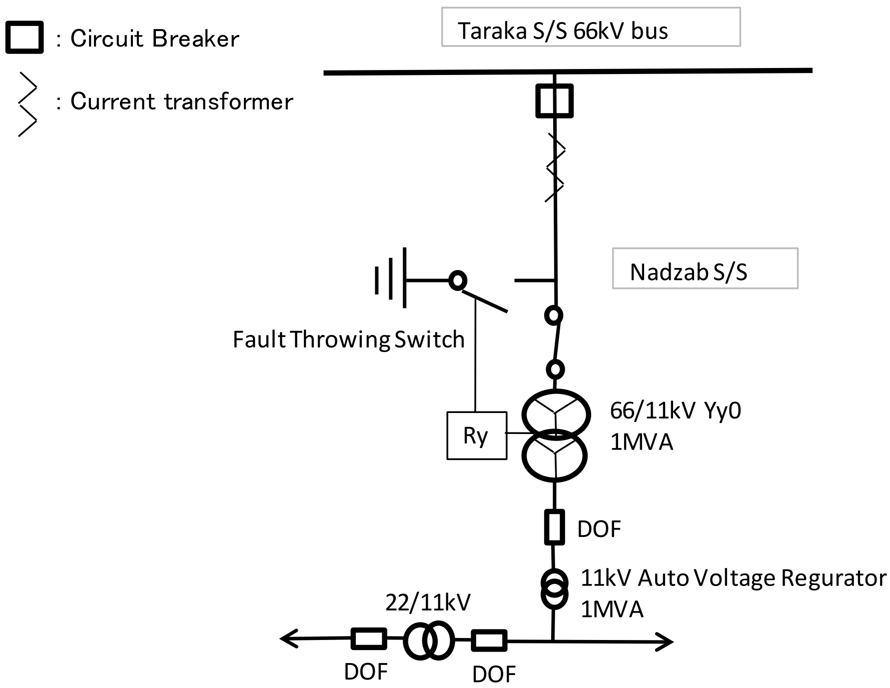
Source: JICA Study Team

Fig. 2.3-16 Milford S/S 11kV Single Line Diagram



Source: JICA Study Team

Fig. 2.3-17 Taraka S/S 11kV Single Line Diagram



Source: JICA Study Team

Fig. 2.3-18 Nadzab S/S Single Line Diagram

The Voltage of the distribution network in the Lae area is 11kV and partially 22kV. The direct earth method is adopted. Secondary winding of 132kV/11kV transformers in Taraka S/S features a star connection and is grounded at a neutral point. Conversely, because the secondary winding of 66/11kV transformers in Milford S/S is a delta-connection, earthing transformers whose secondary winding is zigzag are installed to make a grounding point.

Table 2.3-10 shows each specification of the distribution protection relay. In Taraka S/S, 11kV switchgears were replaced in 2014. Distribution protection relays are installed on the switchgear panel.

In Milford S/S, distribution protection relays are installed in the control room. The D/L of Nadzab S/S is protected by a Dropout Fuse (DOF) because there are no other circuit breakers in the substation outlet.

The T/L between the Taraka and Nadzab S/S (508) is protected by a line protection relay in Taraka S/S. If the transformer installed in Nadzab S/S malfunctions, the Buchholtz relay operates followed by a so-called Fault Throwing Switch. The switch triggers an earth fault deliberately to inform the fault of the transformer.

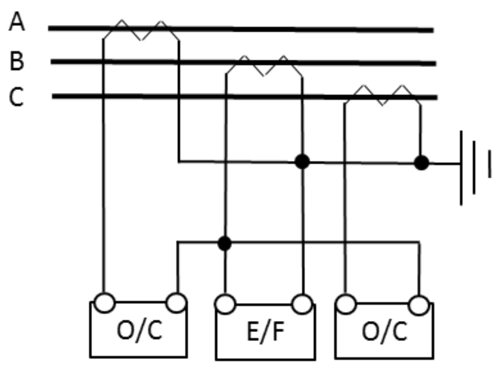
Table 2.3-10 Specification of the Distribution Protection Relay

Substation	Feeder	Type	Model	Method	Connection Diagram
Milford	1	Induction Disc	CDG 31	Short circuit…over current, Earth fault…over current	Fig. 2.3-19
	2	Ditto	Ditto	Ditto	Ditto
	3	Ditto	Ditto	Ditto	Ditto
	4	Ditto	Ditto	Ditto	Ditto
	5	Digital	MiCOM P127	Ditto	Fig. 2.3-20
	6	Ditto	Ditto	Ditto	Ditto
Taraka	1	Ditto	MiCOM P143	Ditto	Ditto
	2	Ditto	MiCOM P142	Ditto	Ditto
	3	Ditto	Ditto	Ditto	Ditto
	4	Ditto	MiCOM P143	Ditto	Ditto
	5	Ditto	MiCOM P142	Ditto	Ditto
Nadzab	No relay (Protected by DOF)				

Source: JICA Study Team

(2) Outline of the Distribution Protection Relay

The protection relay in the Lae area can be divided into two types. One, which is installed in Feeder 1~4 of Milford S/S, is the induction disc type. The other, which is installed in Feeders 5 and 6 of Milford S/S and all feeders in Taraka S/S is the digital type. A diagram of each type is shown in Fig. 2.3-19 and Fig. 2.3-20.



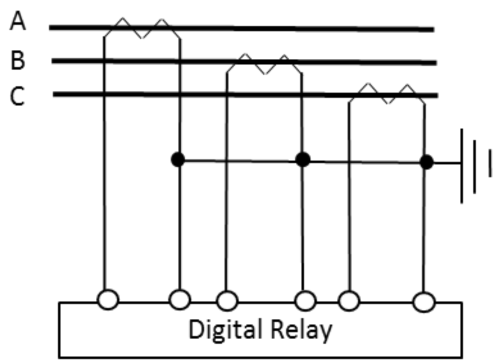
Source: JICA Study Team

Fig. 2.3-19 Milford S/S Feeder 1 ~ 4

In F1 ~ F4 of Milford S/S, the first phase current, which is A phase in the Fig. and the third phase current, which is C phase in the Fig., is input to the short circuit protection relays of the left and right sides. The current combined 3-phase is then input to the earth fault protection relays of the center.

In F5, F6 of Milford S/S, old-type relays like F1~F4 were installed previously. However, digital relays are now installed instead of the old relays.

A 3-phase current is input into the short circuit protection relay, while the zero phase current calculated in the relay detects earth faults. This configuration is the same as F1~F5 of Taraka S/S.



Source: JICA Study Team

Fig. 2.3-20 Milford S/S Feeder 5, 6, Taraka S/S Feeder 1 ~ 5

As stated above, over current relays detect short circuit fault and earth fault in the Milford S/S and Taraka S/S. this configuration meets the Protection Requirements described in the Grid Code. Considering contingencies such as disorder of the distribution protection relay or disorder of the 11kV switchgear in the event of a D/L fault, the relay installed on the secondary side of the transformer plays the role of back-up protection.

(3) Other Protection Relays

1) Auto-Reclosing Relay

Though an automatic reclosing function is installed in the digital relays, the function is set to be disabled. There are no auto-reclosing relays in F1~F4 of Milford S/S. Manual reclosing is sometimes tried in accordance with the system operator instructions in Ramu P/S.

2) Frequency Relay

Frequency relays are installed in the Lae area D/L to supervise the frequency of the Ramu system and operate when the frequency exceeds or goes under the setting value.

Milford S/S has a frequency relay, which sends a trip signal to each feeder. Taraka S/S has a frequency relay per feeder.

The priority of the D/L is decided by whether the D/L supplies important costumers and the amount of electric power it contains. The setting value of frequency relays is adjusted in accordance with the priority.

The under-frequency function is set to enable and the over-frequency function is disabled. Frequency relays prevent the Ramu system from total outage.

Generators in P/Ss are tripped by the frequency relay when the frequency goes below 47Hz or exceeds 53Hz.

The main cause of outages in the Lae area is the operation of frequency relays due to the fault of generators or T/Ls. This process is described in Section 2.6.

3) Transformer Protection Relay

Short-circuit and earth fault protection relays are installed on the secondary side of 66/11kV transformers of Milford S/S and 132kV/11kV transformers of Taraka S/S. These relays play a role in back-up protection when distribution protection relays have a problem.

(4) Setting

The existing distribution protection relays are based on the International Electrotechnical Commission (IEC) standard. Time - current characteristic is set to the Standard Inverse, which is defined in the IEC standard.
There are no rules related to calculating setting values, which are configured by consultants hired by PPL.

1) Setting of short-circuit protection

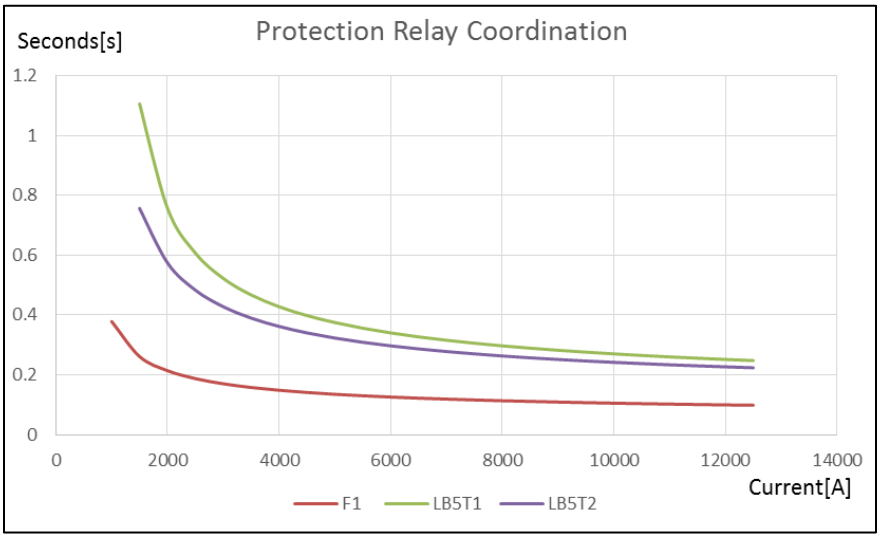
The current tap is set to trip at just over the maximum load current. If the maximum load current of a D/L is 350A, the setting value is 400A for example. Accordingly, most accidents are considered detected. In addition, the value of Time Multiplier Settings (TMS), which determines the trip time, is set to almost the minimum tap such as 0.05 or 0.025 and faults in the D/L are detected as soon as possible.

2) Setting of Earth fault protection

The current tap is set to about 1/5 of the short-circuit protection current setting. In the direct earth system, since the earth fault current is equivalent to the short-circuit current, most faults are considered detected. In addition, the TMS value, which determines the trip time, is set to almost the minimum tap such as 0.05 or 0.025. Faults in the D/L are detected as soon as possible.

3) Coordination with the relay installed in the upper system

A distribution protection relay is set up, taking into consideration coordination with the relay installed in the upper system.
Fig. 2.3-21 shows an example of coordination between the distribution protection relay and transformer protection relay in Milford S/S. The horizontal axis is the fault current and the vertical axis is the operating time of the relay. As the fault current is increasing, the operation time is decreasing in the Standard Inverse.



*1 The time excludes operation time of the relay and circuit breaker.
*2 This example is calculated assuming the fault current of F1 is as same as that of the transformer, in other words, the operating time of the transformer protection relay is minimized.

Source: JICA Study Team

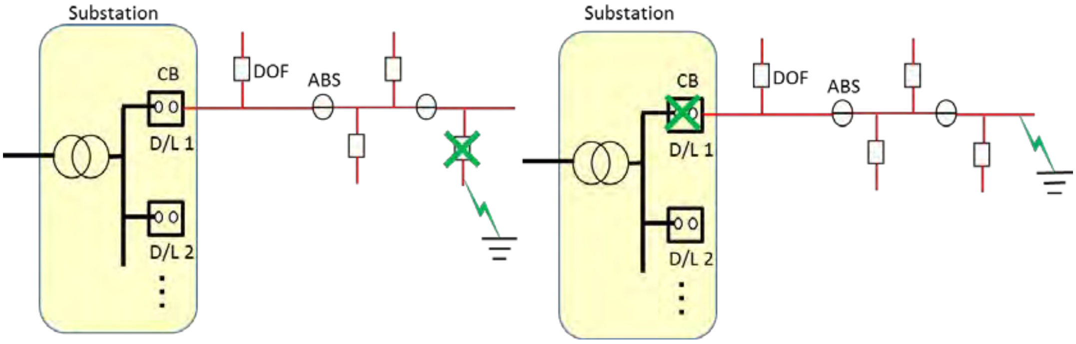
Fig. 2.3-21 Example Coordination between Distribution Protection and Transformer Protection Relays

4) Coordination with DOF

A fuse for protection (DOF) is installed in the D/L. Fig. 2.3-22 shows the role of the distribution protection relay and DOF.

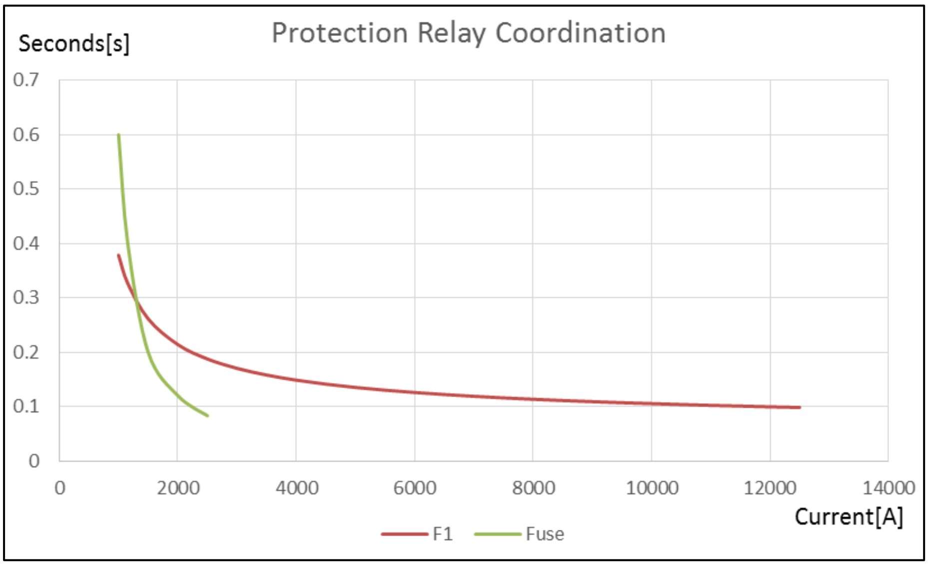
Faults that occurred in a branch line are protected by DOF and those that occurred in the main line are protected by the protection relay in the substation.

Fig. 2.3-23 shows an example coordination between the distribution protection relay and DOF. Within the scope of several thousand amperes flowing at the time of a short-circuit accident, the fuse is triggered earlier than the protection relay.



Source: JICA Study Team

Fig. 2.3-22 Distribution Relay and DOF



*1 The time excludes operation time of the relay and circuit breaker.
*2 The rated current of the fuse is 100A in this calculation.

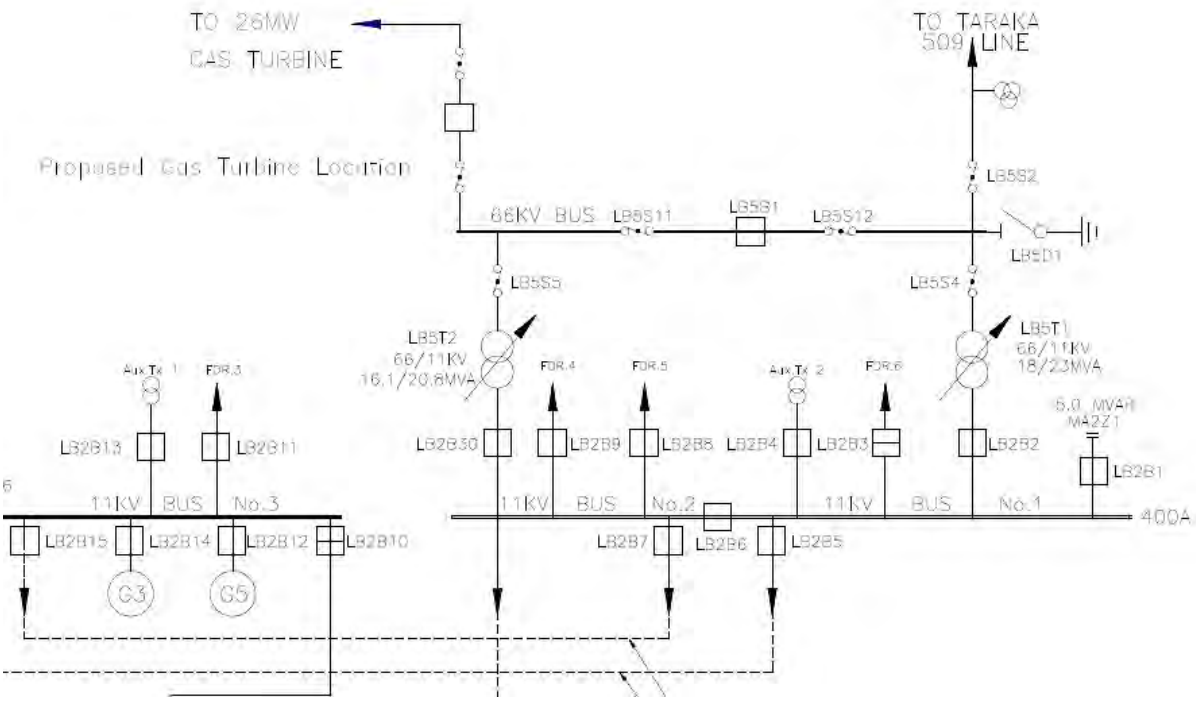
Source: JICA Study Team

Fig. 2.3-23 Example Coordination between the Distribution Protection Relay and DOF

(5) Issue of the Distribution Protection Relay in the Lae Area

An overview of the D/L protection system of the Lae area as indicated above shows no problems in terms of configuring the protection system equipment. Further, since the distribution protection relay are not included in the PPL failure equipment list, urgent measures to improve the relay are not currently required.

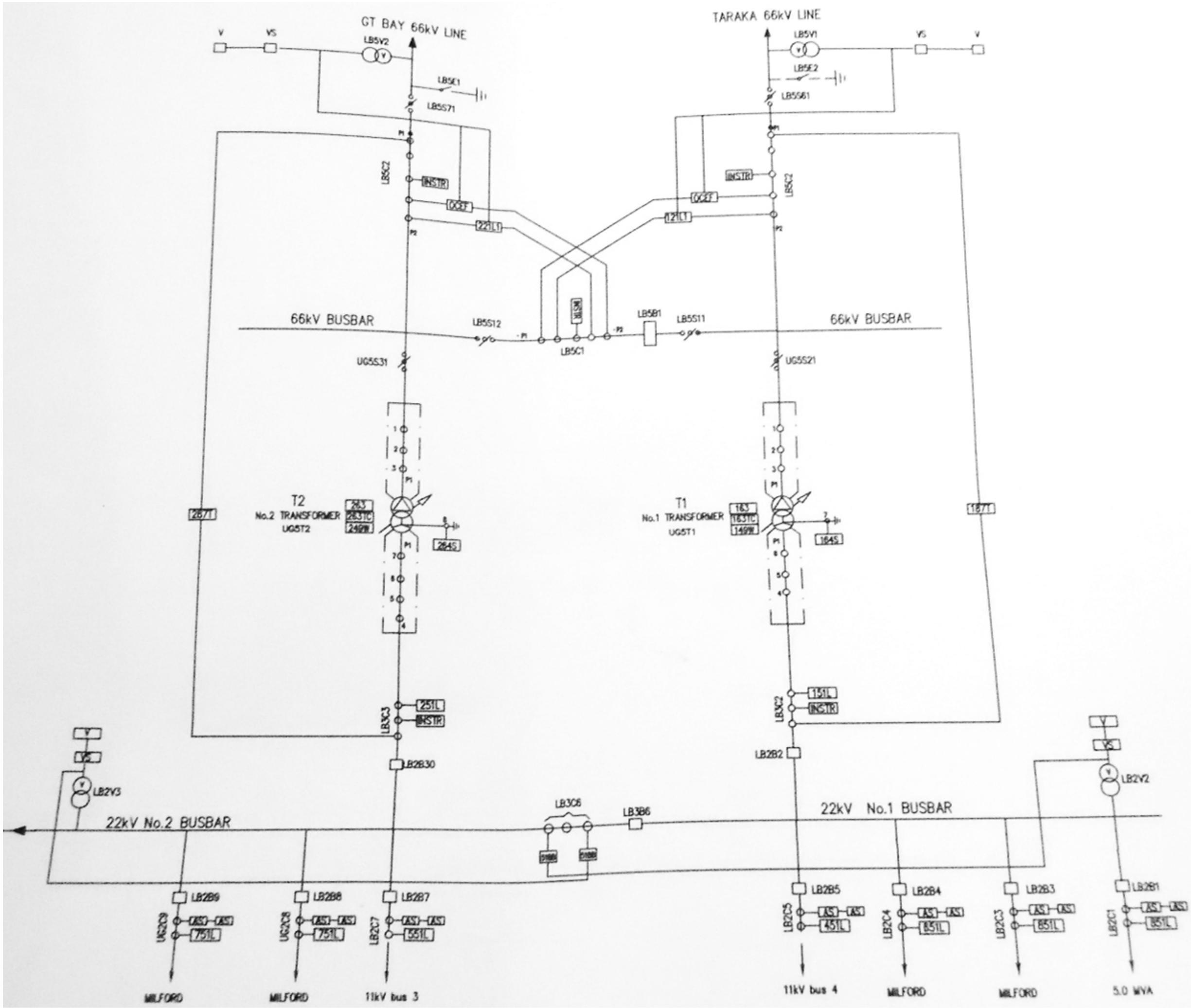
However, as in other sectors, existing drawings are not properly managed. That is one of the issues in the Lae area distribution protection relay. One of the reasons is that the control circuit related to the protection relay is not described in the basic drawing managed in the PPL. Fig. 2.3-24 shows a Milford S/S single-line diagram which is the basic drawing managed by PPL. Only the main circuit is described, not the control circuit related to the protection relay.



Source: PPL

Fig. 2.3-24 Milford S/S Single Line Diagram

Contrary to Fig. 2.3-24, Fig. 2.3-25 shows a Milford S/S single-line diagram made by PPL for the construction work of the new protection relay. Protection Relays, and the Current Transformer (CT) and Voltage Transformer (VT) circuits are described in this drawing. This description is very useful to understand the protection method for this substation at first glance. Additional description of the CT and VT ratios should be included as well as a description of CT, VT and protection circuits in the basic drawing managed by PPL.



Source: PPL

Fig. 2.3-25   Milford S/S Single Line Diagram made for Construction Work

2.4 OPERATION AND MAINTENANCE OF POWER SYSTEMS IN THE LAE AREA

2.4.1 Investigation Purpose to Operate and Maintain a Power System in the PPL LAE Office

The PPL Head Office Department is organized according to Work Function rather than Facilities such as Planning, Design, Maintenance etc.,

The Planning Department establishes a basic and strategic plan to expand the facilities and for technical development etc.

The Design Department in the head office only makes a design with drawings to construct the Power System, including substations, T/Ls & D/Ls.

The Regional Office is only responsible for designing small-scale distribution facilities. (New Pole-mounted transformer installations, Expansion of Low Voltage (L.V.) line, Drop-wire installations etc.)

Although the head office has an Operation & Maintenance Department, the Regional Office mainly conducts maintenance & operation work.

The investigation in this Section was conducted to clarify actual issues regarding Operation and Maintenance (O&M) work and facilities formation in the PPL LAE OFFICE to study an improvement plan for supply reliability and draw up a long-term expansion plan.

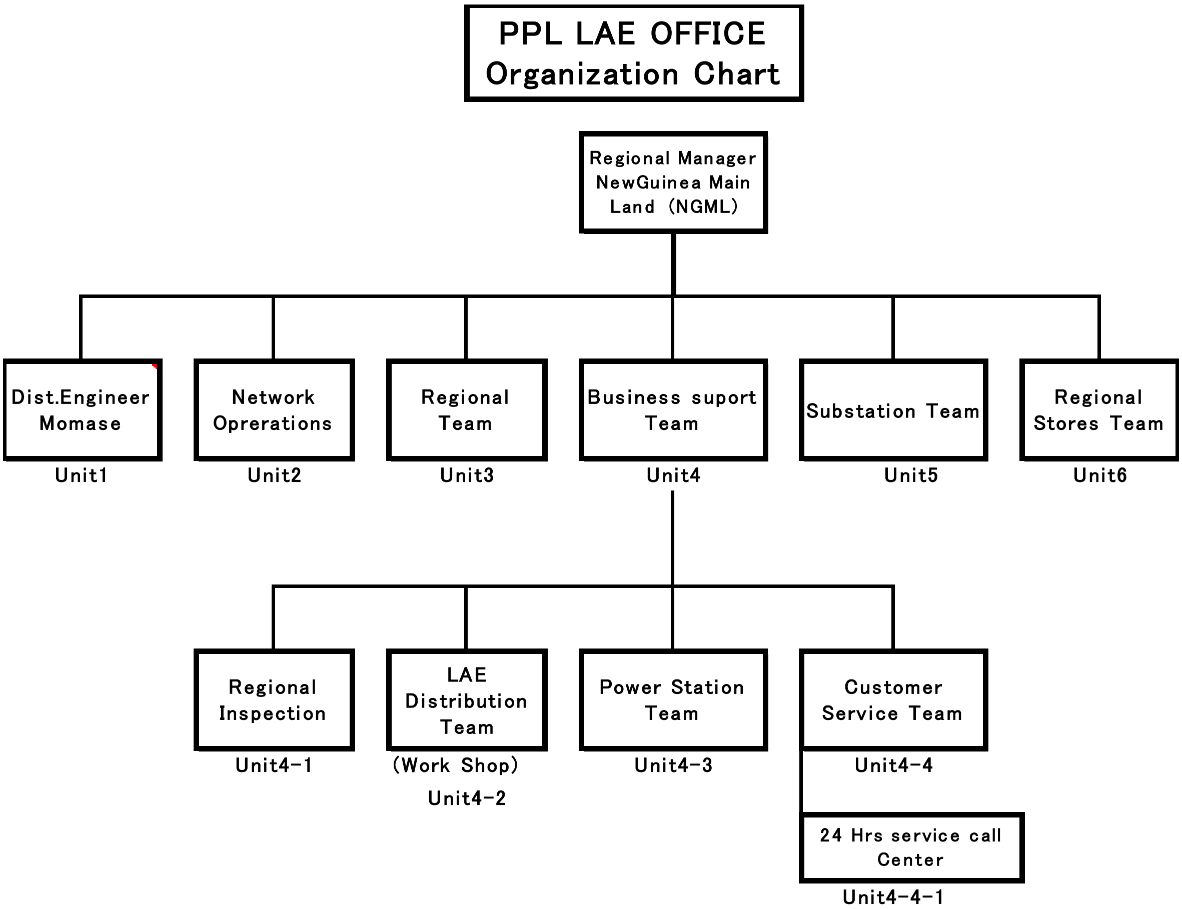
2.4.2 Summary of Organizational Structure & Contents of Work of the PPL LAE Office

(1) Organizational Structure of the LAE office

The PPL LAE structure is shown in Fig. 2.4-1.

The Regional Manager on the PNG mainland manages the entire PPL LAE OFFICE.

The PPL LAE OFFICE is organized into 7 teams & 3 sections and includes duties of business promotion and Operation & Maintenance of power systems in mainland PNG.



Source: PPL

Fig. 2.4-1 Organizational Chart of PPL LAE OFFICE

Appearance of the PPL LAE Signboard of PPL LAE

Fig. 2.4-2 PPL LAE Office

The PPL LAE OFFICE has Team of Operation, maintenance, Customer Service, PPL asset management & Management of Material for Power System etc. (PPL LAE OFFICE referred to as PPL LAE)

As a special mention, PPL LAE exercises jurisdiction over the New Guinea mainland (Morobe, Madan, East & West Sepik) and has no department of Operation & Maintenance for T/Ls.

The PPL LAE has an Operation & Maintenance Department for substation equipment, distribution equipment & power generation plant equipment except T/Ls.

PPL LE also builds up a distribution system. (Distribution Transformer installation, D/L (H.V. & L.V.) expansion, Drop wire installation etc.)

PPL LAE is in charge of D/L Operation & Maintenance at Milford, Taraka and Nadzab S/S.

The target area of JICA Study Team is the LAE area, including Nadzab and Earp.

Accordingly, JICA Study Team focuses on only the distribution facilities of the LAE area.

The role of each Department is shown as follows:

Unit 1 Dist. Engineer
- Management of Distribution System in Momase
- Supply work study for New Customers

Distribution transformer load management

Unit 2 Network Operation
- Distribution system operation (Milford S/S, Taraka S/S, Nadzab S/S)

Unit 3 Regional Team
- Asset management

(Building, materials, land etc.)

Unit 4 Business support Team
- General Customer Service (one-stop service)

Unit 4-1 Regional Inspection
- Inspection of newly installed distribution transformers
- Inspection of customer power facilities
- Installation of electricity meter (W.H.M.) and connection for new customers

Unit 4-2 Lae Distribution Team
- Construction Work of Distribution system
(Erection pole, Expansion of D/L (H.V. & L.V.))
- Installation of Distribution Transformers, Installation of Drop wires)
- Maintenance for Distribution system (except Drop wire)

Unit 4-3 P/S Team
- Operation and Maintenance for small power plants at Milford & Taraka substation

Unit 4-4 Customer Service Team
- Management of a 24 Hour Call Center
- Addressing claims and proposals of customers proposal correspondence
- Installation and maintenance for Drop Wire & W.H.M
- Patrol and Fault location

Unit 4-4-1 24 hour Service Call Center
- Acceptance of customer proposals (24 Hour)
- Installation and maintenance for Drop Wire & W.H.M
- Patrol and Fault location

Unit 5 Substation Team
- Operation and Maintenance of 9 (nine) substations (Taraka, Milford, Nadzab, Erap, Hidden valley, Baiune 1/2, Meiro, Yonki, Gusap & Dobel)

Unit 6 Regional Store Team
- Administration of maintenance equipment for Power Plants, Substation & D/L

(2) Structure and contents of the LAE Distribution Team

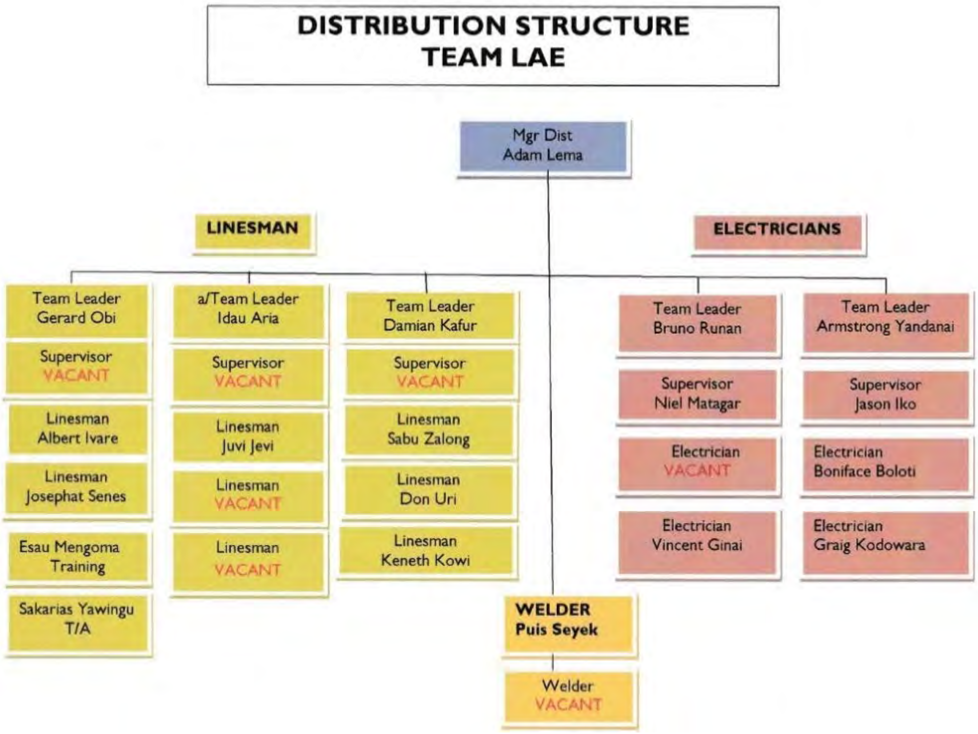
The investigative purpose of JICA Study Team for Operation & Maintenance of the distribution System in Lae is to facilitate a study of the short-term distribution network improvement plan in Lae to improve urgent issues affecting PPL LAE.

Accordingly, JICA Study Team investigated operation work, construction work, maintenance work and fault recovery work of the distribution system at LAE distribution team and 24 Hr. service Call Center.

1) Structure of the LAE distribution team

The LAE Distribution team (workshop) comprises three line teams, two electrician teams and one welder section, as shown in Fig. 2.4-3.

Lae Distribution Team (workshop) Photo is shown in Fig. 2.4-4.



Source: PPL LAE distribution team

Fig. 2.4-3 Structure of the LAE Distribution Team

Campus of the Lae Distribution team Office of the LAE distribution team & 24 hour service Call Center

Fig. 2.4-4 Office of the LAE Distribution Team

2) LAE distribution team contents

(a) Lines Man team

Construction work for D/L (H.V. & L.V. lines, Drop Wire)

Maintenance work for D/L (H.V. & L.V. lines except Drop Wire)

Line Man is an official name in PPL. PPL Head Office has issued a certificate to persons having engaged in special line man training at Port Moresby (POM). Only Line Man is permitted to turn ABS on or off.

(b) Electrician team

Construction and Maintenance for Distribution Transformers

(c) Welder section

Production of Steel Poles, Steel Arms, Pole-mounted Switch operation rod and Pole-mounted Transformer Support etc.

2.4.3 Operation and Maintenance for Transmission Systems, Substations and Distribution Systems in Lae

T/L (132kV, 66kV), 3 substations (Taraka, Milford, Nadzab) and an 11kV D/L are installed in the Lae area. However, the Ramu control center (Ramu C/S) operates a transmission system, substation and distribution system (includes pole-mounted switch). Because this operation may impact on the Ramu system, Ramu C/S instructs the order of operation to each system operator. However, Ramu C/S delegates the authority of the 11kV D/L to PPL LAE Network Operation.

(1) Status of Operation and Maintenance for Transmission Lines

PPL LAE has not conducted maintenance and operation for T/Ls, only Ramu C/S has done so. Also, Ramu C/S has conducted fault location and recovery work, so JICA Study Team has not yet performed a detailed survey.

(2) Status of Operation and Maintenance for Substations

1) Current Status of Operation and Maintenance for Substations

PPL LAE has implemented 9 substations (including Milford, Taraka, Nadzab) in mainland.

JICA Study Team performed a detailed survey of three substations (Milford, Taraka, Nadzab).

(a) Current Status of Operation for substations

The operator engages in 24-hour operation and monitoring of circuit breakers (132, 66 and 11kV) and transformers (132kV /66kV, 132kV /11kV, 66 / 11kV) at Taraka & Milford.

The Nadzab substation is unmanned and has one transformer (66 / 11kV, 10MVA).

The operator of the Taraka substation engages in monitoring and maintaining for the Nadzab substation.

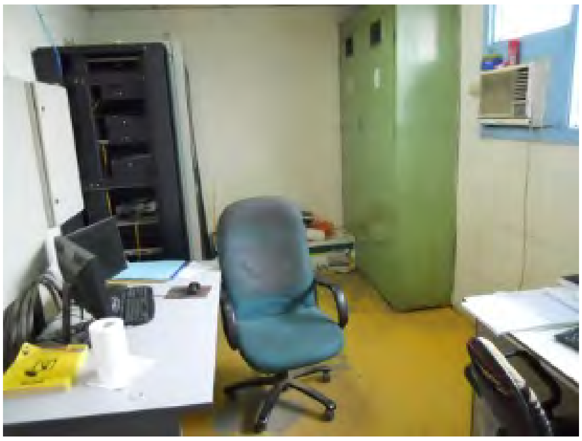
The above operation (except for the 11kV circuit breaker) is performed as instructed by Ramu C/S.

(b) Current issues of operation clarified for substations

The key issue in substation operation is that operators do not always notice faults because no alarm is sent to the operator. For example, when an 11kV switchgear is tripped due to a distribution fault, no alarm is sent to the room where the operator works. Accordingly, the operator does not notice an emergency and recovery from the outage is delayed. It is important to notify emergency situations via the Supervisory Control And Data Acquisition (SCADA) system as soon as possible.

In the Ramu system, installation of a SCADA system is planned. This SCADA project is described in the Chapter 7 of the Ramu system development plan.

Fig. 2.4-5 shows the room where the operator of the Taraka substation works. The SCADA system of Erap and Hiddenvalley, as shown in Fig. 2.4-5, has been already installed. Accordingly, while the operator cannot supervise and control the Taraka substation, he/she can manage the Erap and Hiddenvalley substations in this room. Control and monitoring panels are lined up in the next room and the operator can control equipment such as circuit breakers.



SCADA system in the Taraka substation *Control room of the Taraka substation*

Fig. 2.4-5 Control Room of the Taraka Substation

(c) Current issues of Operation for substation

Maintenance for substations in the Lae area is conducted by the substation team, which mainly involves inspecting the substation, replacing old facilities and coping with faults. A general inspection is conducted based on a one-year plan, where the substation team confirms whether or not any faults exist with their own checklist in general inspection. They change silica gel in the breather and cut grass in the substation. Their general inspection plan is shown in Fig. 2.4-6.

Erap Substation	6 days	Wed 14/05/14	Wed 21/05/14
General Inspections and Clean up	6 days	Wed 14/05/14	Wed 21/05/14
Check done according to Substation Inspection and Check List	2 days	Wed 14/05/14	Thu 15/05/14
Fuel Top up for Stand By Genset	2 days	Fri 16/05/14	Mon 19/05/14
Grass Cutting	2 days	Tue 20/05/14	Wed 21/05/14
Gusap Substation	7 days	Thu 22/05/14	Fri 30/05/14
General Inspections and Clean up	7 days	Thu 22/05/14	Fri 30/05/14
Travel Lae Gusap	1 day	Thu 22/05/14	Thu 22/05/14
Check done according to Substation Inspection and Check List	2 days	Fri 23/05/14	Mon 26/05/14
Silica Gel inspection and change	1 day	Tue 27/05/14	Tue 27/05/14
Grass Cutting	2 days	Wed 28/05/14	Thu 29/05/14
Travel Gusap Lae	1 day	Fri 30/05/14	Fri 30/05/14
Hamata Substation	7 days	Mon 02/06/14	Tue 10/06/14
General Inspections and Clean up	7 days	Mon 02/06/14	Tue 10/06/14
Travel Lae Hamata	1 day	Mon 02/06/14	Mon 02/06/14
Check done according to Substation Inspection and Check List	2 days	Tue 03/06/14	Wed 04/06/14
Silica Gel inspection and change	1 day	Thu 05/06/14	Thu 05/06/14
Grass Cutting	2 days	Fri 06/06/14	Mon 09/06/14
Travel Hamata Lae	1 day	Tue 10/06/14	Tue 10/06/14

Fig. 2.4-6 Scheduled General Inspection Plan

In case they replace old facilities and cope with faults, they procure the necessary facilities for replacement and usually proceed without the manufacture's help. Fig. 2.4-7 shows the replacement of arresters on the primary side transformer when JICA Study Team visited the Taraka substation.

Both the primary and secondary side transformers were earthed during the maintenance work. A safety belt was attached and a ladder used to prevent falling, emphasizing the importance of safety.

Fig. 2.4-7 Replacement of Arresters

(d) Current issues of Maintenance for substation

Management on the drawings of old facilities, particularly control circuits, seems to be ignored. When some faults happen, it takes them a long time to determine the circuit. Consequently, it seems that the recovery time is extended. Where some faults happen in the control circuit, drawing a control circuit is important to clarify the cause. If they try to make the drawing after the fault happens, the recovery time is prolonged by the duration. It is desirable for them to prepare and order the drawings before any emergency happens. However, it is inefficient to survey all the drawings they have because it takes too long. It is important to reserve drawings such as control circuit drawings, with which the new control panels are installed and edit them when the panel is customized.

(3) Status and Issues for Operation and Maintenance for Distribution facilities

JICA Study Team performed a detailed investigation, which included interviews about day-to-day operations work and maintenance in PPL LAE and extracted issues by accompanying fault recovery work.

1) Current Status and Issues of operation work of the distribution line

(a) Current Status of operation work of distribution line

“Network Operations” in PPL LAE involve instructing the operator on the operation of the 11kV distribution system.

- ♦ Network operation work
  Network operation have issued instructions to operate the 11KV distribution system to the substation operator and the team-leader of the lineman.
- ♦ Substation operator work
  The substation operator has performed the operation involving turning the 11kV Circuit Breaker (CB) on or off at the substation as instructed by Network Operations.
- ♦ Lineman Team leader work
  The Lineman Team leader has also performed the operation of turning the switch on the 11kV D/L on or off as instructed by Network Operations

Distribution system diagram (shown in Fig. 2.3-2 and Fig. 2.3-3) is essential for these operations.

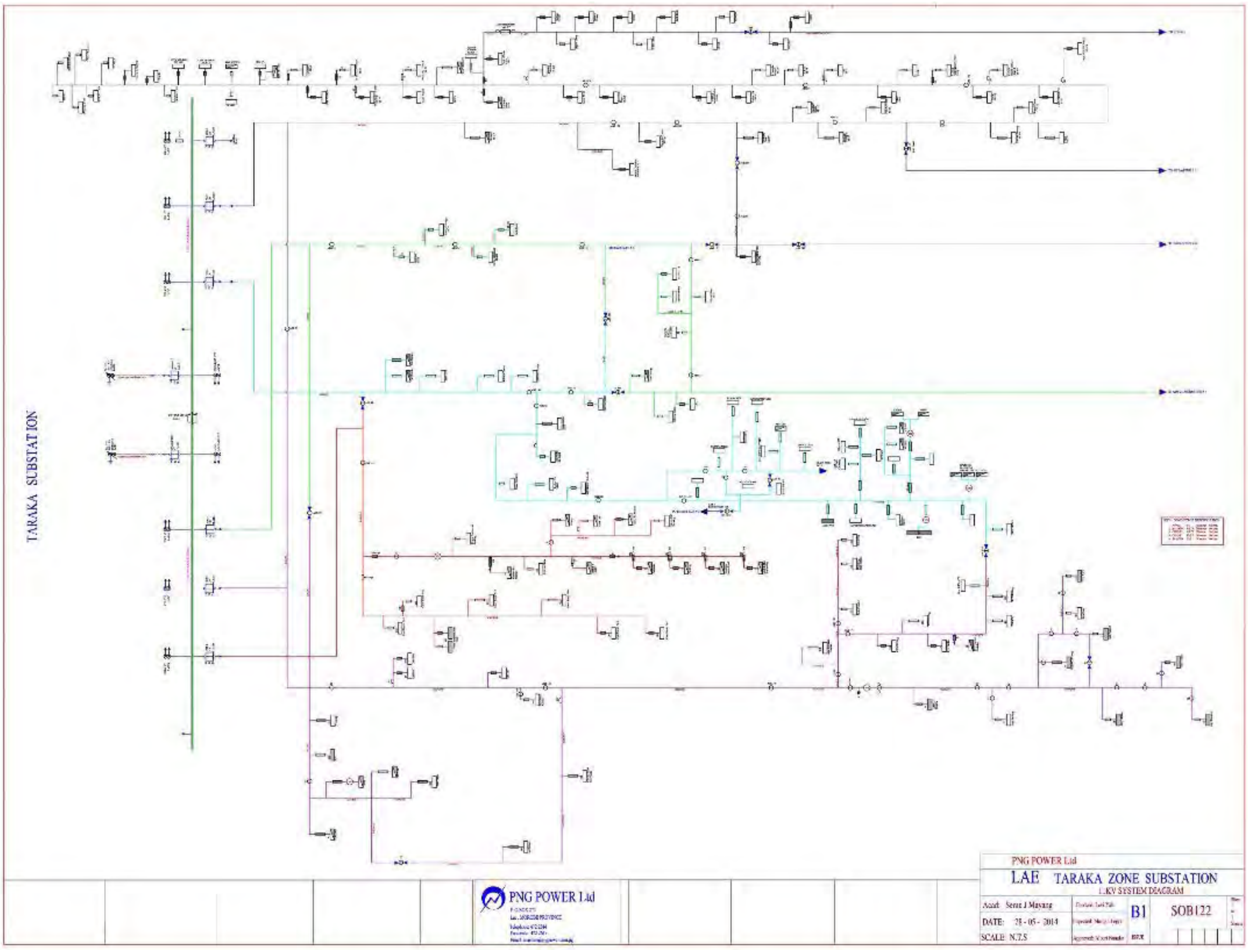
JICA Study Team checked that data, but distribution system diagram has not been updated for six months.
Although a distribution system diagram has been updated by Network operation even late six months.
Person of Network operation has personally modified distribution system diagram. JICA Study Team was afraid about the occurrence of human error which may complicate the system in future.

An updated distribution system diagram is basic data for distribution operation work.

JICA Study Team conducted interviews on the current situation with the team leader of the workshop and conducted a field survey to completed distribution system diagram

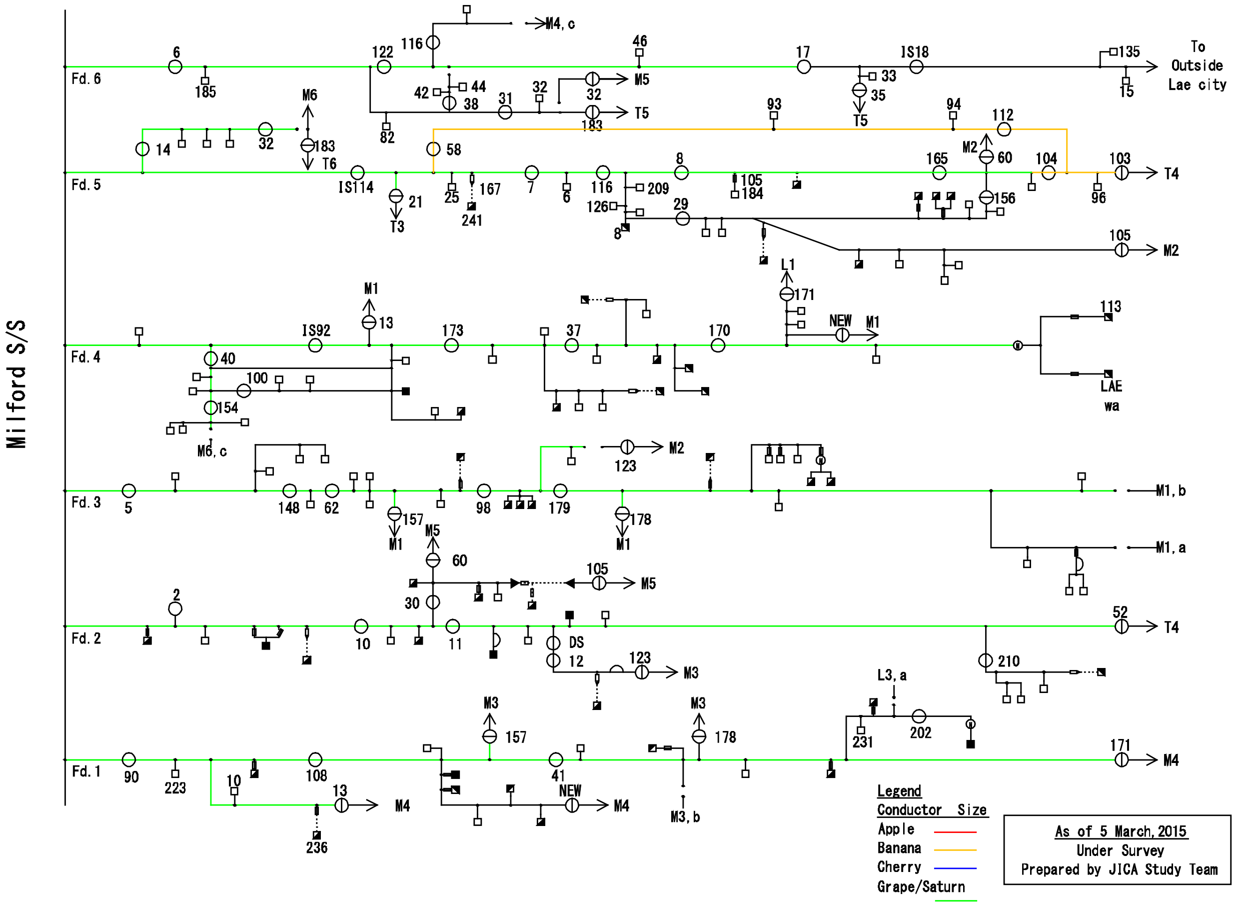
JICA Study Team also interviewed the current team leader of workshop and conducted a field survey.

The old distribution system diagram is shown in Fig. 2.4-8. An updated distribution system diagram by JICA Study Team is shown in Fig. 2.4-9. An updated distribution system diagram which is required for switching to transfer load and isolation of the distribution section during fault or maintenance work, etc. is essential data. However, no mechanism currently exists to systematically update the document for facilities management.



Source: PPL LAE

Fig. 2.4-8 Old Distribution System Diagram



Source: JICA Study Team

Fig. 2.4-9 Updated Distribution System Diagram

(b) Issue for operation work of distribution line

♦ Network operations

- There is only one person in charge of system operation in “Network operations”.
- Human error is likely to occur when the system is complicated in future.
- In the absence of the person assigned to instruct on system operations, which is inconvenient, Ramu C/S should perform instructions as the agency.

♦ Distribution diagram & update system

- There is no clarification of rules and responsibilities which ensure updating of the distribution system diagram
- When personnel changes and retirement are conducted, their successors must first start determining the current distribution system from scratch
- There is no mechanism to prevent human error among operational personnel
- Human error is likely to occur when the system is complicated in future.
- Inoperable switches have not been indicated in the system diagram, despite installing those switches in the current line.

2) Current Status and Issues of Maintenance (construction) work for distribution facilities

(a) Maintenance structure for distribution system

Distribution systems are consisted of poles, H.V. lines, switches, lightning arresters, transformers and L.V. lines and drop wires etc. and have spread to areas.

Distribution system maintenance, since the equipment is in contact with the customers, many abnormalities occur information and facilities complaint.

Since the two offices (24Hrs service Call Center and workshop) is doing the maintenance work.

(b) Current Status of the maintenance work of 24Hrs service Call Center

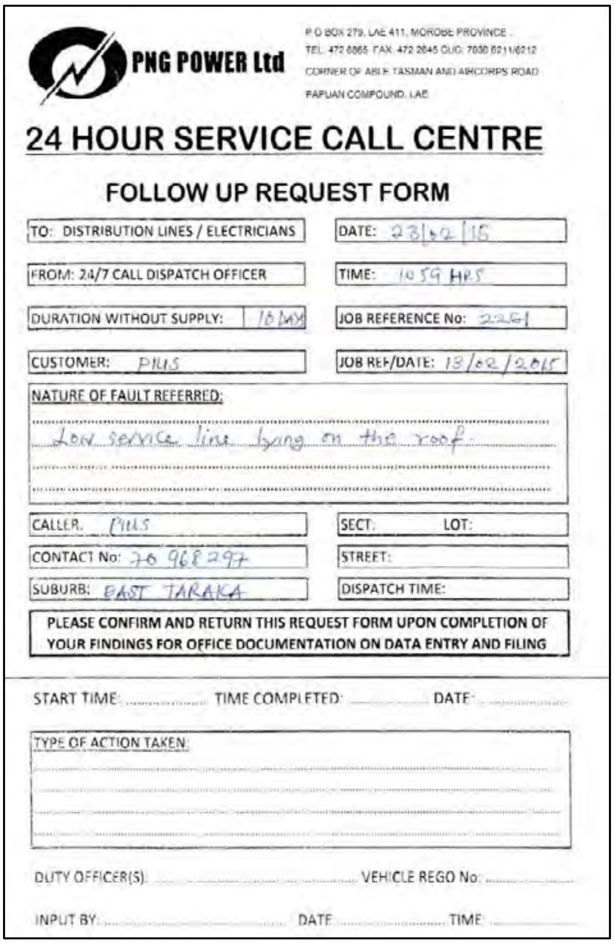
- 24 Hrs. Service Call Center issues a processing table (Fig. 2.4-10) depending on the offer of more customers.
- 24 Hrs. Service Call Center sends the processing table except drop wire relation to the corresponding part.
- 24 Hrs. Service Call Center when a D/L accident is performed early patrol, perform certain fault point.

Although the maintenance work of 24 Hrs. Service Call Center is Drop wire relationship, this study is focusing on improving the supply reliability of the H.V. D/L.

Accordingly, here, further investigation will be omitted.

However, from the perspective of using the equipment correctly when preparing the master plan for the distribution facilities, there is a possibility of the transformer load management becoming significantly problematic in case of increasing demand caused by supply for new customers.

In that case, investigations for the Customer Service Team should be repeated.



PNG POWER Ltd
P O BOX 279, LAE 411, MOROBE PROVINCE
TEL: 472 6865 FAX: 472 2645 CUG: 7030 6211/6212
CORNER OF ABLE TASMAN AND AIRCORPS ROAD
PAPUAN COMPOUND, LAE

24 HOUR SERVICE CALL CENTRE

FOLLOW UP REQUEST FORM

TO: DISTRIBUTION LINES / ELECTRICIANS
DATE: 23/02/15
FROM: 24/7 CALL DISPATCH OFFICER
TIME: 1059 HRS
DURATION WITHOUT SUPPLY: 10 MN
JOB REFERENCE No: 2261
CUSTOMER: PIUS
JOB REF/DATE: 13/02/2015
NATURE OF FAULT REFERRED: Low service line hang on the roof.
CALLER: PIUS
SECT: LOT:
CONTACT No: 76 968 297
STREET:
SUBURB: EAST TARAKA
DISPATCH TIME:
PLEASE CONFIRM AND RETURN THIS REQUEST FORM UPON COMPLETION OF YOUR FINDINGS FOR OFFICE DOCUMENTATION ON DATA ENTRY AND FILING
START TIME: .... TIME COMPLETED: .... DATE: ....
TYPE OF ACTION TAKEN:
DUTY OFFICER(S): .... VEHICLE REGO No: ....
INPUT BY: .... DATE .... TIME ....

Fig. 2.4-10 Follow Up Request Form

(c) Current Status and Issues of operation and maintenance work of workshop

a) Current Status of Maintenance work of workshop

- Replacement of defective equipment is the major maintenance work.
- Replacement of overload transformer.
- Replacement of defective equipment at the time of the D/L fault.

In addition, a workshop as described above is also performing new construction work. The workshop has not yet replaced the aging equipment as planned.

b) Organizational Structure of the workshop

The workshop, which divides the LAE district into three tissues as shown in Fig. 2.4-3, has performed the work by sharing each region in the Lines man group of 3 teams.

The distribution System diagram and route map of the D/L (H.V. & L.V.) are important data to ensure the safety of construction and maintenance work.

However, the H.V. D/L route map has not been updated for more than a decade and no route map of the L.V. D/L exists.

The latest information on the diagram and route map is memorized by each line man team leader.

JICA Study Team is concerned about possible human error if the system becomes more complex in future.

The updated D/L route map (H.V. & L.V.) is basic data for distribution system maintenance and construction work.

JICA Study Team conducted interviews about current situation to the team leader of the workshop and has completed the latest D/L route map (H.V.) based on the field survey by themselves.

No replacement of the distribution equipment has yet been updated on the D/L route map.

Distribution equipment is subject to significant variation in factors, e.g. extended by switching and new loads based on load situations or accidents, but no data update mechanism.

The old route map (H.V.) is shown in Appendix B-5. An updated D/L map (H.V.) by JICA Study Team is shown as Fig. 2.3-2 and Fig. 2.3-3.

c) Issues of workshop maintenance and construction

- The D/L map has not been updated since ten years ago and is just memorized by the team leader.
  (The D/L map is the basis for distribution system maintenance and failure to update to the latest version may lead to injury)
  (Information not taken over in the event of absence or when personnel changes, retirement of team leader)
  (Not changing the shared area of the team)

To develop a future plan, first, there is a need to collect information on existing facilities.

However, in the system diagram, the mechanism of current facility management was insufficient.

JICA Study Team took the time to conduct a field survey.

3) Current Status and Issues for Operation and maintenance in distribution systems during accidents

Encounters in D/L accidents during the second survey were conducted for research from accident exploration to recovery and power re-supply.

Describe the actual situation and problems of maintenance and operation from this work series.

(a) Accident overview

Ground faults by H.V. line anchor points with one conductor coming off due to corrosion of the wooden arm, as shown in Fig. 2.4-11.

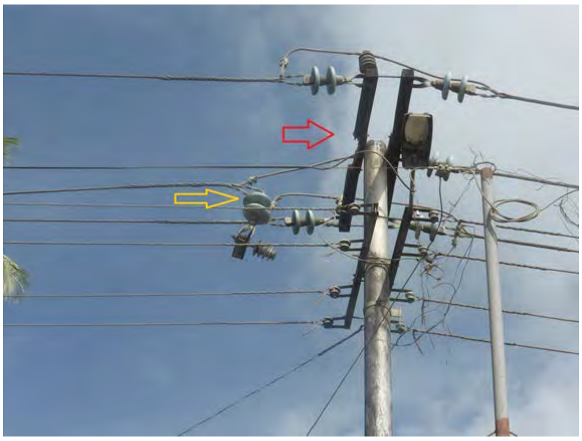
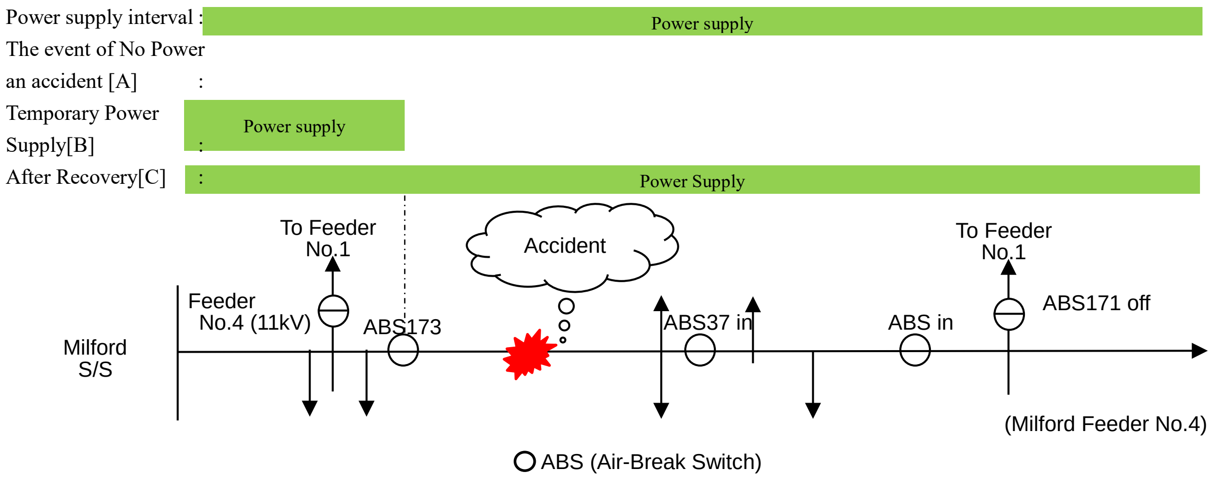


Fig. 2.4-11 Distribution Accident Overview

Date & time : 27, February, 2015

Place : Lae city Milford Feeder No. 4

Process :
- 08:55 Milford Feeder No. 4 (11kV) Trip (Relay function : phase B O.C & Earth fault)
- 09:00 Milford S/S has informed Trip information to 24hrs Service Call Center
- 09:05 Milford S/S operator has turned on Milford feeder No. 4 (11kV) by manual. Milford Feeder No. 4 (11kV) re-Trip
- 09:20 2 Call Center Worker has started patrol
- 09:26 Worker found out the utility pole over than 2 span from ABS173 and confirmed the Cross arm corruption. Worker informed accident location to Milford S/S operator in radio. Patrol car directly went to accident location. (It seems a patrol car knew the information of accident location)
- 09:40 Network operator has order turning off ABS173. Work shop lineman has turned off ABS173. (Operation on no power)
- 10:06 Milford S/S operator has turned on Milford Feeder NO.4 Power supply completion from Milford S/S to ABS173 (Corresponding to B in Fig. 2.4-12)
- 13:26 Wooden Arm replacement completion
- 13:32 Turned on ABS173 (on hot line) Feeder No. 4 Entire interval power recovery (Corresponding to C in Fig. 2.4-12)



Source: JICA Study Team

Fig. 2.4-12 Power Recovery Situation and Accident Interval

(b) Issue for operation in distribution line accident

On this accident, Worker had the information of the accident location.

So, the temporary power supply has been completed in a short time.

However, Recovery step that is according to the accident recovery procedure of PPL (shown in Fig. 2.4-13) is shown as bellow.

Step 1: Turn off ABS 173 and Turn on Milford No4 CB.

Step 2: Turn off ABS 37
Turn off Milford No4 CB.
Turn on ABS 173.
Turn on Milford No4 CB.

Also, JICA Study Team has interviewed from PPL Head Office operation department that PPL implement the emergency power supply except for the fault section.

But, PPL has never implemented the emergency power supply.

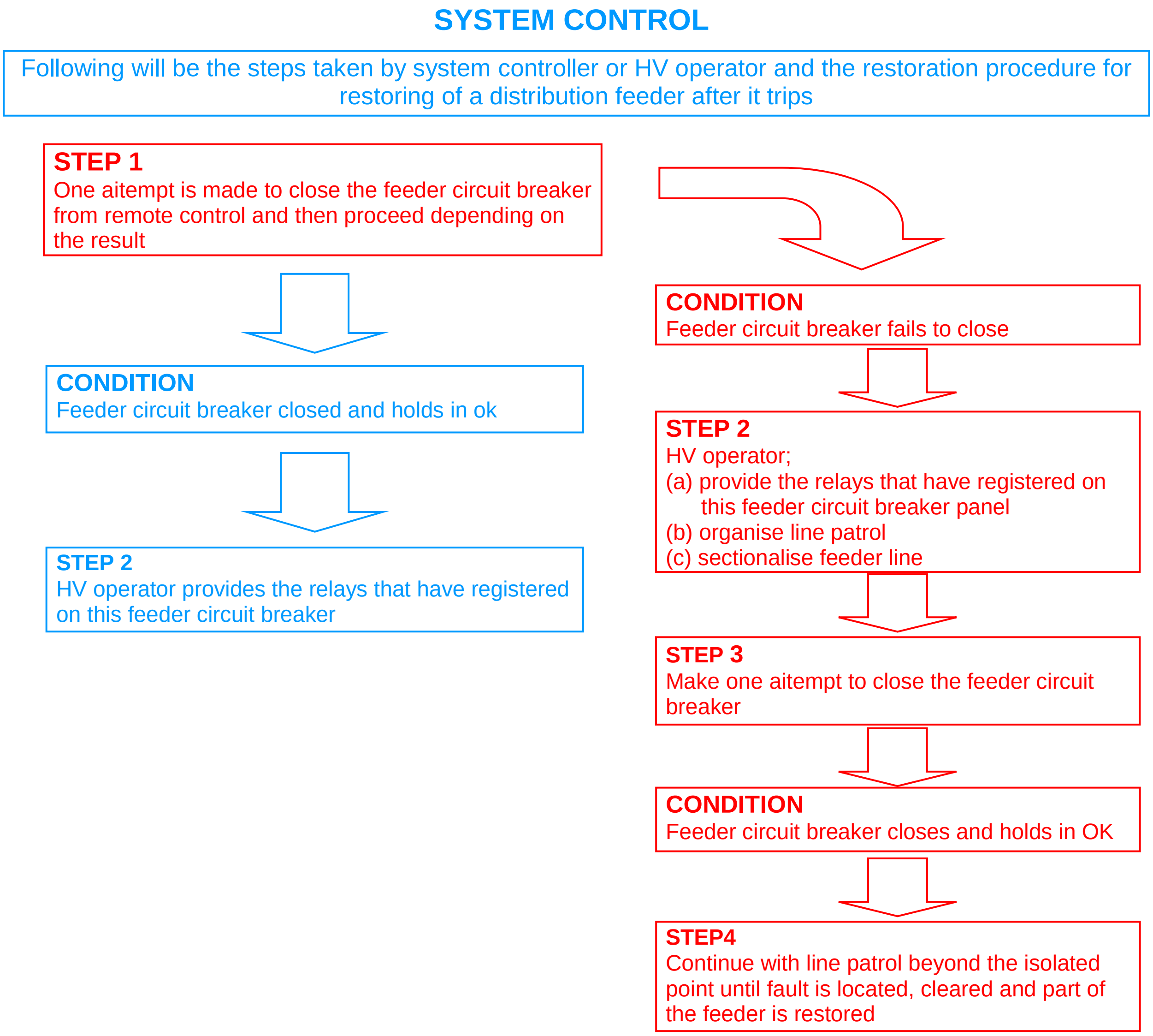


Fig. 2.4-13 System Operation Procedure for Fault Location

This process is that D/L has not been connected with other D/Ls in rural areas.

In this case, this process is an effective process.

However, there are many connected with other D/Ls in urban areas.

The immediate power supply is desired in urban area.

It is not be said to be an effective recovery method as viewed from the side of power supply reliability.

In other words, when a D/L accident occurs, quickly power supply for healthy section is an important concept.

JICA Study Team has also interviewed from PPL Head Office operation department that the emergency power supply except for the accident interval is an important concept.

In a series of operation work in this D/L accident, temporary power supply interval is only up between substation and ABS173.

After confirming fault point

STEP1: Turned off ABS173 and ABS37
STEP2: Turned on Milford No4
STEP3: Turned on ABS 171

This Step means the minimization of accidents blackout section.

That is to improve the power supply reliability.

[Matters to be upgrading facilities to improve the supply reliability by such operations] is as follows;

- A section of the D/L should be to standardize
- Adoption section switch that can do load break
- The connected point with other D/L is to install the switch that can do load brake
- To ensure the rated current of feeder of D/Ls, the conductor-size should be to the proper size

[Matters to amend the manual of system control to improve the supply reliability by such operations] is as follows;

- Establishment of temporary power supply

(c) Current status for construction work for repair

a. The concept of safety

♦ Earthing for safe work

- PPL Process (The procedure performed by lines men)
- STEP1 Installing terminal of earthing shown in Fig. 2.4-14 (A) on conductor on the power supply side the working section
- STEP2 Implanting an earthing rod into the ground (shown in Fig. 2.4-14 (B))

(A) Mount work ground

(B) Implanting ground rod

Fig. 2.4-14 Repair Works

Above mentioned procedure is improper. Proper procedure is as follows:

Recommended procedure

STEP1 Implanting a ground rods into the ground
(ensuring the earth potential for safety)

STEP2 installing the earthing terminal on conductor

[Safer installation ground]
To ensure the safety of the work area, it is necessary to attach the ground at the both side of working area (Protection to the power supply from the other D/L)

b. Lack of equipment and tools

- ♦ Lack of tools

  This work is one replacement work of the double arm on steel pole. (Shown as Fig. 2.4-15 (A))

  The workshop line man team has only 2 Wire Clampers (Fig. 2.4-15 (B)).

  If workshop lineman team has 3 Wire Clampers, it is not necessary to repeat the conductor holding work.

- ♦ Lack of equipment

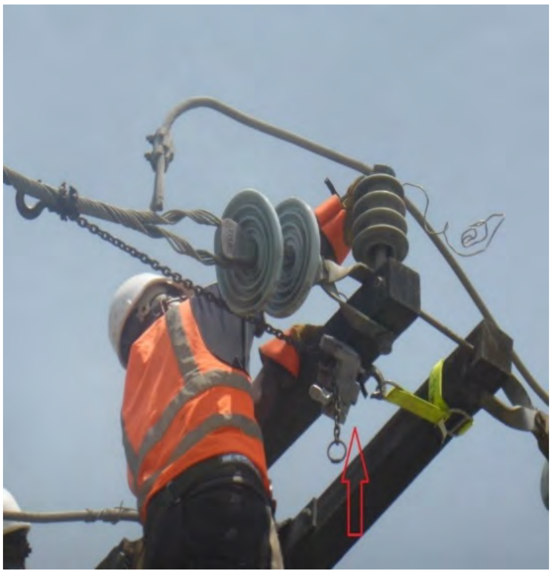
  [Tool bag]

  When the worker has rose to the pole, the worker has minimum quantity tools for safety.

  After rising the pole, the worker has lift up the tools and materials from the ground by the rope.

  On lifting up, some of these was falling down.

  If PPL worker has used tool bag (shown as Fig. 2.4-15 (C)) with a rope to put the tool bag, it is possible to prevent falling.



(A) Pulling conductor by Clamper

(B) Clamper

(C) Tool bag

Fig. 2.4-15 Repair Tools

(A) Lifting arm by rope

(B) Lifting insulator by rope

(C)Work on pole

Fig. 2.4-16 Work on Pole

These Photos (Fig. 2.4-16) has showed work on the pole.

In this case, the worker should use the platform on pole for the secure.

It is not recommended to ride on the conductor, because there is a possibility of conductor broken or the like.

In this case, the using of the platform (shown as Fig. 2.4-17) on the pole has ensured the safety for the work area.

Fig. 2.4-17 Platform on Pole

♦ Effective use of equipment

The aerial work platform is used for L.V. hot working (Fig. 2.4-18) in workshop of PPL Lae.

H.V. line working are carried out in a power outage work

Accordingly, if PPL use such aerial work platforms, PPL will be able to implement a safe and efficient work.

Fig. 2.4-18 Aerial Work Platform

(d) Issue for maintenance and construction work

- Safety method of construction interval does not correspond to the change in equipment.
- Tool is missing the number of members when performing a standard work.
- Tool is insufficient
- Effective use of equipment is not able to others.

JICA Study Team got the information of any overload transformers from workshop

The reason that there are overload transformers, seems not to be load management of the transformers.

For load management, to consider whether done in On the Job Training (OJT) to further investigation of the current way.

2.5 POWER LOSS OF POWER SYSTEM

2.5.1 Outline of Power Loss of Power System in the Lae Area

According to the FIFTEEN-YEAR POWER DEVELOPMENT PLAN (FYPDP) Ramu POWER SYSTEM (2014-2028) PPL, System losses of the Ramu system[1] is 21.23%. However, breakdown of losses such as power consumption from station use is unknown.

Clarification of power loss in a general way is as shown in Fig. 2.5-1.

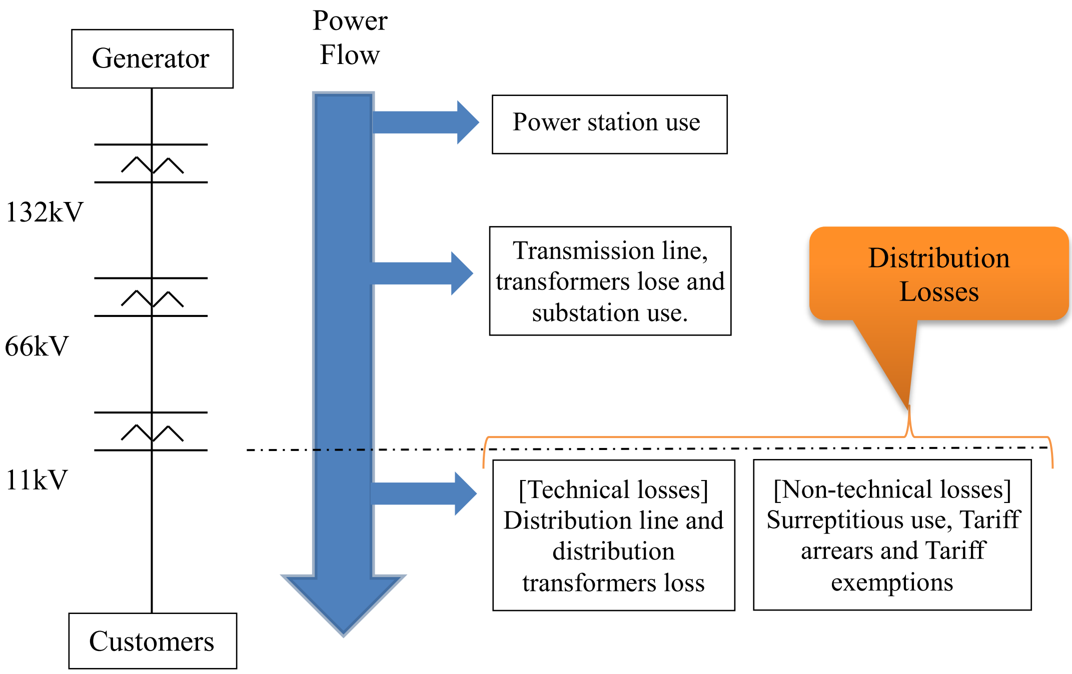


Fig. 2.5-1 Classification of Power Loss

2.5.2 Distribution Loss and Remedial Measures

Distribution loss is classified in a general way as follows:

(1) Technical loss

Resistance loss is caused by the electrical resistance of cable and varies in proportion with the square of current. In developing countries, it is thought to be a generally high level. This is because, even if the demand increases, there is a tendency to refrain from increasing the capacity of transmission and D/Ls and consequently to supply power in an overload status as well as to unreasonably extend D/Ls to curtail costs.

Transformer (iron) loss arises due to the iron cores of transformers. It varies in proportion with the transformer capacity, but is unrelated to the size of load. Even though they have the same capacity, transformers built in recent years have less iron loss than those built 30 or more years ago. There have also appeared low-loss models using an amorphous type of iron core.

1 Power loss is calculated as the difference between generated energy and energy sold in PPL.

(2) Non-technical loss

While the definition of non-technical loss varies with the country, the three basic types are surreptitious use, tariff arrears and tariff exemptions.

The term "surreptitious use" (power theft) refers to illegal use of power by a customer via supply that is not routed through the meter. Consequently, this use is not included in the amount of power sales measured by the meter. There are two kinds of tariff arrears (non-collection): 1) that from cases in which the power utility cannot collect charges for the amount of power use measured by the meter (i.e., non-payment) and 2) that caused by mistaken measurement by defective meters. The term "tariff exemptions" refers to the practice of supplying power free of charge to governmental agencies as well as for street lights and other public facilities. In some countries, it is not counted as loss.

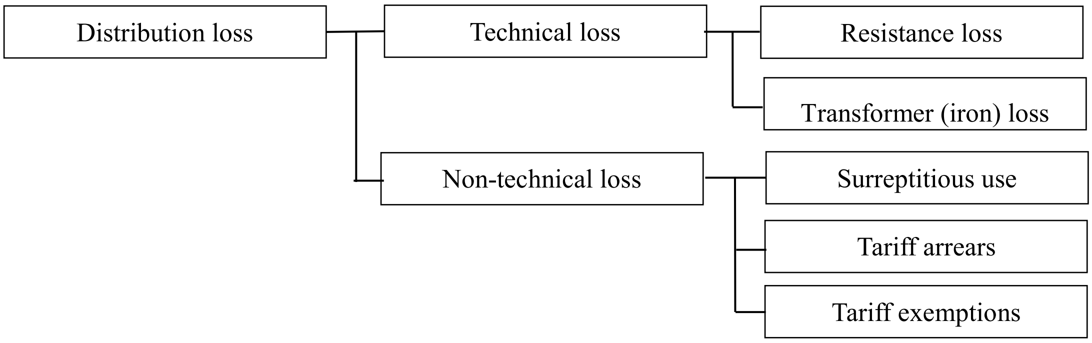


Fig. 2.5-2 Classification of Distribution Loss

(3) Measures to reduce technical loss

Table 2.5-1 outlines specific measures to reduce technical loss in distribution systems. Distribution loss requires an area-wise implementation of these measures, which can have an enormous effect for reducing loss. Considering the cost-benefit factor, it would therefore be uneconomical to undertake construction aimed solely at loss reduction; it is the normal practice to execute the measures along with other construction. For this reason, it would be more realistic to view measures for reduction of technical loss with a timeframe of about 10 years as opposed to the shorter term.

The following table presents the findings of analysis and examination in this development study for distribution loss in the Lae area.

Table 2.5-1 Power Loss

Classification		Actual situation of the distribution network in the Lae area		
		Causes	Area	Actual situation, evaluation and Measures
Resistance Loss	22kV, 11kV distribution lines	Low demand density	Urban Area	Demand density is from 0.39 to 8.29 MW/m^2. Length of D/L is 8 km on average. There are no problems caused by mismatch between the demand density and the equipment specification. Not necessary to take a measure in the short term improvement plan.
			Rural Area	Low-capacity load is scattered over a wide area and 22kV D/Ls are extended for long distances (over 60 km) from Nadzab S/S. In the long-term future, some measure may be required, but, in the short term, there is no cost performance. Accordingly, when increasing in a load of the D/L in rural area remarkably, consideration will be required again.
		Improper voltage	Urban area	From the perspective of the result of demand forecast until 2030, there is reasonable to reinforce the distribution network as existing voltage (11kV). If the system voltage is changed to 22kV from 11kV, the huge cost for re-construction is required.
			Rural Area	From the perspective of the result of demand forecast until 2030, there is reasonable to reinforce the distribution network as existing voltage (22/11kV). If the system voltage is changed to more than 22kV from existing voltage, the huge cost for re-construction is required.
		Improper conductor size	Urban area	Thin conductor with Apple or Banana (Cross-sectional area of 49.5 or 77.3mm^2) are used for the trunk parts of D/Ls. This is presumably causing the resistance loss on trunk lines of thin conductor. The measure is required. Thin conductors on the trunk line replace to proper conductor size in short-term distribution improvement plan.
			Rural Area	Thin conductor with Cherry (Cross-sectional area of 120mm^2) are used for the trunk parts of D/Ls. However, from the perspective of the amount of load (0.99MW), the effect with conductor size up is not expected so much.
		Imbalanced current among 3-phases.	Urban area	Result of power quality measurement, imbalanced current between 3-phases are not measured. There is no problem.
			Rural Area	In this stage, there is no data, when increasing in a load of the D/L in rural area remarkably, consideration will be required again.
Transformer (iron) loss	Distribution Transformer	Large-capacity transformers	Urban Area Rural Area	There are apparently many cases of installation of transformers with an extremely high capacity as compared to the total demand, even in area that have a small demand at present and no firm prospects for a major increase in the future. In the long-term future, some measure may be required such as demand management method at distribution transformers, JICA Study Team continue the survey about this issue and consider in the technical guidance stage.

2.6 FAULT RECORD ANALYSIS

In the first field survey, our study team collected the one year record of the outages in the Lae area distribution network from October 2013 to September 2014. The record is collected in Operation system department in POM. Our study team analyzed this record to clarify the issue of Lae area distribution network.

2.6.1 The Outline of the Outage Record

Operation system department in POM collect records by one outage of one D/L. For example, 6× are counted in case of the outages in all 6 D/Ls of Milford S/S due to the T/L fault.

One record is shown in Fig. 2.6-1. This figure shows that Milford S/S F1 is off from 8:05 to 9:23 on 1/Oct/2013.

Date	Feeders	Fdr #	Customers Affected	Off	On	Mins	Hrs	MW	MWHr	Cause	Status	Remarks
1-Oct-13	Milford	1	995	8:05	9:23	78	1.30	2.89	3.7570	D1	up	UF tripped due to low freq.

Source: PPL

Fig. 2.6-1 Record of Distribution Outages

Our team select the following record to clarify the issue on the Lae area distribution network.

Target records for analysis: outage records from 1/Oct/2013 to 30/Sep/2014 in Taraka and Milford S/S (Total number of outages is 2919)

2.6.2 Clarification of Outages by PPL

PPL classifies the causes one by one. Classification by PPL is shown in Fig. 2.6-2.

CAUSE SYMBOLS for OFR

A HUMAN AGENCY
Vehicle, etc. striking poles or conductors. Switching (including switching overload), testing, vandalism, falling trees on equipment, failing to carry out routine task.
A1 PPL personnel responsible
A2 Other than PPL personnnel responsible
A3 Acts of Vandalism

B FORCES OF NATURE
B1 Trees or part thereof
B2 Other than trees or part thereof
B3 Lightning
B4 Not found during storm (but attributed to storm conditions).

C APPARATUS FAILURE
C1 PPL equipment.
C2 Consumers and other authorities responsible
C3 Poles and Cross arm fires

D OVERLOAD
D1 PPL responsible – Load shedding.
D2 Consumers and other authorities responsible.

E BIRDS/ANIMALS

F UNKNOWN
Nil found (other than B-4)

Source: PPL

Fig. 2.6-2 Cause Symbols

In accordance with these cause symbols, the outage records are classified in Table 2.6-1.

Table 2.6-1 Clarification of Outages by PPL

Feeders	A1	A1/D1	A2	B1	B2	B3	B4	C	C1	C1/D1	C1/F	C2	D1	D1/C1	D2	F	F/A1	F/C1	Total
Milford	66	1	11	10		2		4	851	33	5	2	374	8	8	67	1	4	1447
Taraka	71	2	13	12	1	2	2		877	38	5		305	13	9	120		2	1472
Total	137	3	24	22	1	4	2	4	1728	71	10	2	679	21	17	187	1	6	2919

Source: JICA Study Team

C1 (Apparatus Failure-PPL equipment):59%,
D1 (Overload-PPL responsible – Load shedding):23%

The number of these two causes is larger than the others.

However, this result can only inform that there are many apparatus failures in PPL. It is impossible to know what kind of apparatus have failures.

2.6.3 Classification of Outages by JICA Study Team

It is impossible to clarify the issue from PPL's way of classification.

The records are classified according to the equipment segment that triggered the outage of D/Ls such as generator, transmission and distribution equipment from the Remarks column. The classification example and classification result are shown below.

Classification example

Remarks column	Classification
"Tripped on U/F caused by Ramu U3 TRIP"	"Other than distribution - Generator"
"Fdr on b/o due to L601 fault"	"Other than distribution - Transmission"
"Fdr L/S to improve system frequency"	"Other than distribution – Generator or Transmission" (there is no relation between frequency and distribution)
"Fdr tripped on E/F"	"Distribution"

U/F : Under Frequency   Fdr : Feeder   b/o : Black Out
L/S : Load Shedding   E/F : Earth Fault

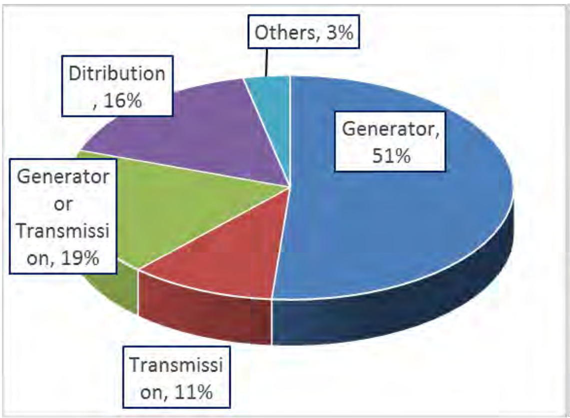
Table 2.6-2 Classification of Outage Records

Other than distribution	Generator	1578
	Transmission	313
	Generator or Transmission	582
Distribution		343
Others (impossible to classify)		103
Total		2919

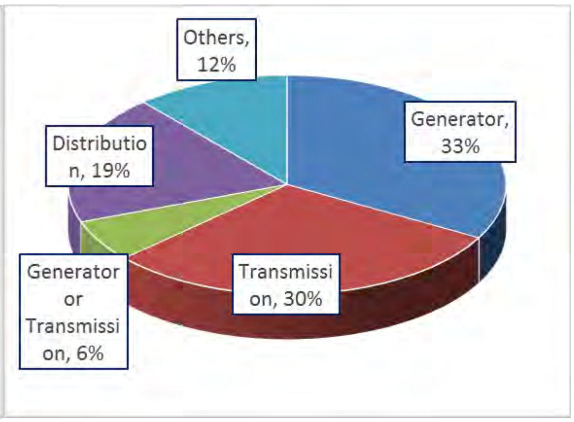
Excluding 103 outages classified in the Others (impossible to classify), the number of outages due to the Distribution is 343 (12%) of 2816. The number of outages due to the Other than distribution is 2473 (88%).

This result shows the outages in the Lae area distribution network are mainly caused by Other than distribution such as generator and transmission.

For reference, System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) calculated by each facility is shown in Fig. 2.6-3.



SAIFI (Total 265 times/customer/year)



SAIDI (Total 13490 minutes/customer/year)

Source: JICA Study Team

Fig. 2.6-3 SAIFI and SAIDI (Each Facility)

2.6.4 Analysis of the Outages due to Reasons Other than Distribution

This section shows the process of the outages caused by generator and transmission.

(1) Outage caused by Generator

1578 outages caused by generator are classified to the three types, “Operation of frequency relay”, “Load shedding” and “Others”. Table 2.6-3 shows the classification.

Table 2.6-3 Classification of Outages caused by Generator

Example of Remarks column	Classification	Number
Tripped on U/F caused by Ramu U3 TRIP	Operation of frequency relay	952
Fdr L/S due to generation shortfall	Load shedding	504
Ramu U5 trip	Others	122

Source: JICA Study Team

The number of outages classified to Operation of frequency relay is 952. In Ramu system, due to the large single machine capacity of the generator against the system capacity, the frequency of the system varies greatly when the single generator trips. Frequency relays installed in the D/Ls are set to 48Hz. If the frequency decreases more than 2Hz from 50Hz due to the trip of generator, frequency relay operates and D/Ls are tripped.

In this way, a failure of the generator is affecting the D/L.

As system capacity of the Ramu system increases in the future, accidents of this nature are expected to decrease. However, it is considered that this condition persists for a while. To reduce the outages caused by generator, the reduction of the failure in the generator which trigger the distribution outages is the most important.

The number of outages classified to Load shedding is 504.

Due to generator failure or less supply capacity, the balance of supply and demand is lost. Consequently, the load shedding is conducted on a command of the system operator in Ramu.

For other cases, how the generator affected the D/L is not described. It is considered most of other cases are classified to Operation of frequency relay or Load shedding.

From the above, the reduction of the generator fault is the key to reduce the number of outages caused by generator.

(2) Outage caused by Transmission

313 outages caused by transmission are classified to the two types, “L601 trip” and “Others”. Table 2.6-4 shows the classification.

Table 2.6-4 Classification of Outages caused by Transmission

Example of Remarks column	Classification	Number
Fdrs on black out when L601 tripped	L601 trip	169
Fdr tripped off when Taraka TX-1 CB tripped open	Others	144

Source: JICA Study Team

The number of outages classified to L601 trip is 169. The number of outages caused by transmission is less than ones caused by generator but the outage duration per once is longer.

Most of the power supplied to Lae area supplied by one of the T/Ls from Ramu power plants. Accordingly, when the T/L is tripped due to the contingency such as the lightning fault, power supply to the D/L is interrupted.

To improve this situation, it is necessary to reinforce the T/L so as to continue supply during single line fault. Specifically, it is necessary to make double circuit T/L from Ramu to Lae area.

Currently, the project to reinforce the T/L of the Ramu system is planned in yen loan. After the completion of the construction, the number of outages caused by transmission is considered less.

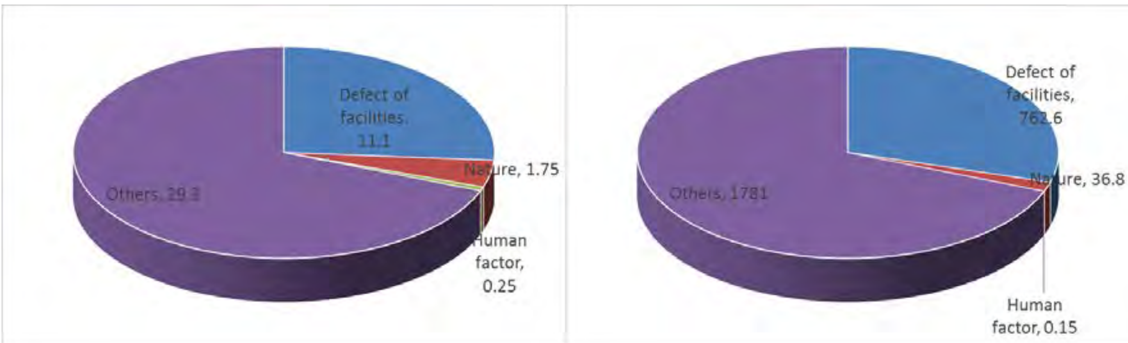
(3) Outage caused by Generator or Transmission

The outages whose cause is not written clearly in Remarks column but is considered generator or transmission are classified to this category. Total number is 582. The number of outages related to the frequency drop is 456 (78%). Events as described in 4.1 and 4.2 appears to be going on.

2.6.5 Analysis of the Outages caused by Distribution

343 outages caused by distribution are classified to the four types, “Defect of facilities”, “Nature”, “Human” and “Others”.

SAIFI and SAIDI calculated from the outages caused by distribution is shown in Fig. 2.6-4.



SAIFI (Total 42 times/customer/year) SAIDI (Total 2581 minutes/customer/year)

Source: JICA Study Team

Fig. 2.6-4 SAIFI & SAIDI (Distribution)

Consequently, the most of the outages are classified to Others. 80% of the others described only a relay operation. It is impossible to find out the cause of the outage. The cause of the outage is not written or they cannot find the cause of the outage.

Defect of facilities was the next many number of supply interruptions cause. From the Remarks column, it is read that the power outage is caused by a variety of equipment such as arm, DOF and ABS. The proportion of the outage due to equipment failure is not so large.

From the above, it can be said that it is difficult to reveal the major cause of the D/L fault from the outage data of PPL.

In addition, of the 343 times, more than one hour of power outage was 123 times. Their total power failure time is 399 hours, average power outage time is 3.2 hours.

2.6.6 Summary of Fault Record Analysis

As mentioned above, the following is clarified from outage record.

- Outages caused by power generation or transmission are 88% of the total.
- Outages caused by distribution are 12% of the total.
- It is effective to reduce the failure of the generator and enforce T/L to reduce the outages.
- For the outages caused by distribution, there are more than 50 percent of the total whose cause is unknown or not written.

To collect a better statistical record to analyze the cause of outages and plan the measures, the following things are recommended.

(1) The record should be classified to the each facility which triggered outages same as the above mentioned.

However, distribution outages due to the fault of Ramu power plant are almost happening at the same time in various places of the Ramu system. Accordingly, in the current Ramu system without a SCADA system, it is difficult to figure out what triggered the blackout. Now, PPL get in touch with the various places by phone and consider what happened. In the future, after introduction of a SCADA system, it is possible to record automatically the change and the alarm of the Ramu system. That record makes it easy to determine accidents and collection outage data.

(2) The cause of the fault should be recorded in detail.

In the future, to reduce the number of outages, it is important to identify the cause and develop a countermeasure. The equipment which triggered outages such as arm and ABS is written in some records but only the operation of protection relay is described in more than half of the records. Since the events that triggered the protection relay operation is the key information, it is desirable to record it in detail as much as possible.

2.6.7 Policy of Short-Term Distribution Network Improvement Plan from this Analysis

This result shows that it is difficult to clarify the main cause of the outage in the Lae area distribution network from this outage record. The measures for individual outage cause such as deterioration, lightning, salt contamination, etc. cannot be specified without sufficient statistical data.

In short-term distribution network improvement plan, JICA Study Team focuses to reduction of outage duration rather than reduction of outage frequency to improve the supply reliability.

2.7 POWER DEMAND IN THE LAE AREA

Power demand of each 11kV feeder is being recorded manually by the operating staff of PPL Lae at Taraka substation and Milford substation.

2.7.1 Recording Method of Power Demand within the Distribution Network

Recording method of power demand, Location of measurement point by each feeder power demand are shown in Table 2.7-1 and Fig. 2.7-1.

Conversion from current (A) to power demand (MW) is applied by the following expressions.

$$\textit{Power demand (MW)} = \textit{Current (A)} / 65.6$$

Source: PPL

The above-mentioned expression can be interpreted to be the following:

$$\textit{Power demand (MW)} = \textit{Current (A)} \times 11\ (kV) \times \sqrt{3}\ \times 0.8\ [\textit{Power Factor}] / 100{,}000$$

Source: JICA Study Team

Table 2.7-1 Recording Method of Power Demand

Items	Taraka S/S	Milford S/S
Record Interval	1 hour	30 minutes
Record Items	Power Demand (MW)	Power current (A)
Number of Feeders (Transmission line)/ Voltage	5 Fdr. (Taraka)/11kV 1 Fdr. (Nadzab)/66kV	6 Fdr. (Milford)/11kV
Method of Record	Manual (Visual inspection)	
In charge of Record	Operators of substation	

Source: JICA Study Team

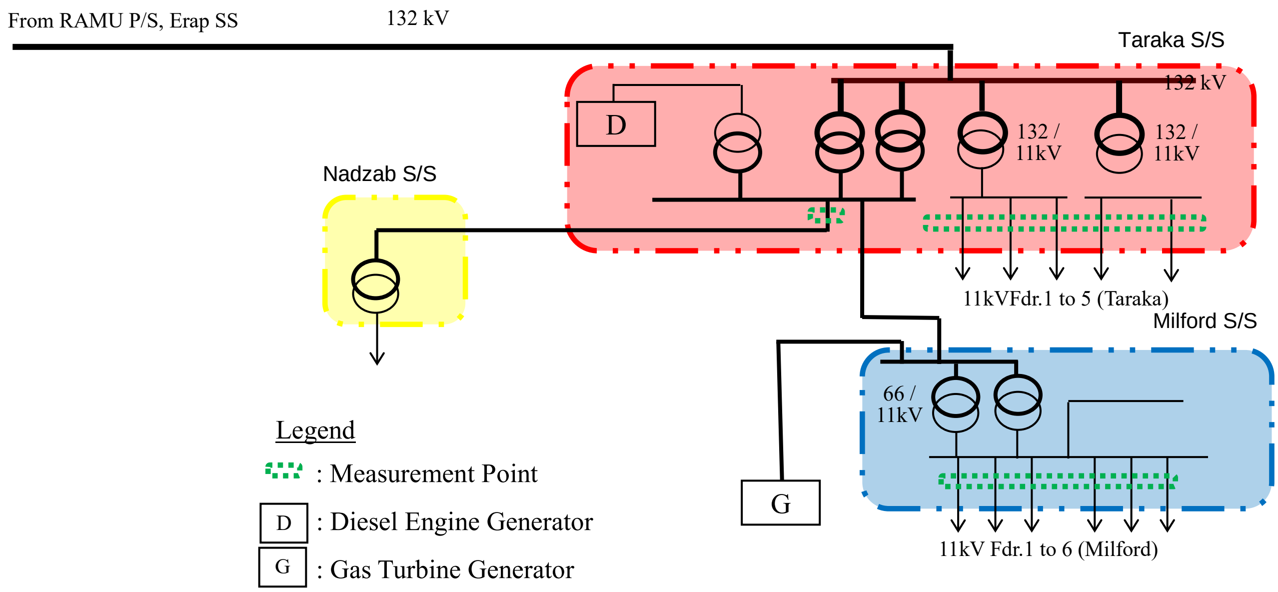
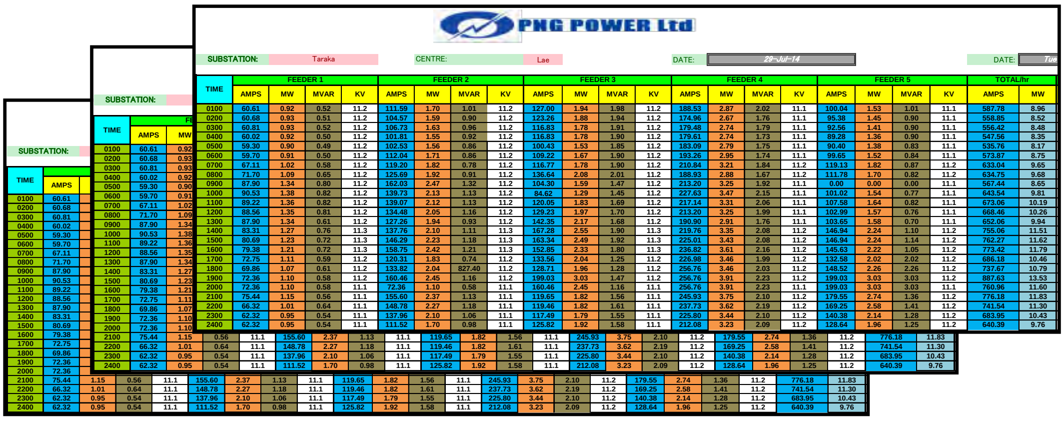


Fig. 2.7-1 Location of Measurement Point by Each Feeder Power Demand

Source: JICA Study Team



PNG POWER Ltd

SUBSTATION: Taraka CENTRE: Lae DATE: 29-Jul-14 DATE: Tue

TIME	FEEDER 1				FEEDER 2				FEEDER 3				FEEDER 4				FEEDER 5				TOTAL/hr	
	AMPS	MW	MVAR	KV	AMPS	MW	MVAR	KV	AMPS	MW	MVAR	KV	AMPS	MW	MVAR	KV	AMPS	MW	MVAR	KV	AMPS	MW
0100	60.61	0.92	0.52	11.2	111.59	1.70	1.01	11.2	127.00	1.94	1.98	11.2	188.53	2.87	2.02	11.1	100.04	1.53	1.01	11.1	587.78	8.96
0200	60.68	0.93	0.51	11.2	104.57	1.59	0.90	11.2	123.26	1.88	1.94	11.2	174.96	2.67	1.76	11.1	95.38	1.45	0.90	11.1	558.85	8.52
0300	60.81	0.93	0.52	11.2	106.73	1.63	0.96	11.2	116.83	1.78	1.91	11.2	179.48	2.74	1.79	11.1	92.56	1.41	0.90	11.1	556.42	8.48
0400	60.02	0.92	0.50	11.2	101.81	1.55	0.92	11.2	116.83	1.78	1.90	11.2	179.61	2.74	1.73	11.1	89.28	1.36	0.90	11.1	547.56	8.35
0500	59.30	0.90	0.49	11.2	102.53	1.56	0.86	11.2	100.43	1.53	1.85	11.2	183.09	2.79	1.75	11.1	90.40	1.38	0.83	11.1	535.76	8.17
0600	59.70	0.91	0.50	11.2	112.04	1.71	0.86	11.2	109.22	1.67	1.90	11.2	193.26	2.95	1.74	11.1	99.65	1.52	0.84	11.1	573.87	8.75
0700	67.11	1.02	0.58	11.2	119.20	1.82	0.78	11.2	116.77	1.78	1.90	11.2	210.84	3.21	1.84	11.2	119.13	1.82	0.87	11.2	633.04	9.65
0800	71.70	1.09	0.65	11.2	125.69	1.92	0.91	11.2	136.64	2.08	2.01	11.2	188.93	2.88	1.67	11.2	111.78	1.70	0.82	11.2	634.75	9.68
0900	87.90	1.34	0.80	11.2	162.03	2.47	1.32	11.2	104.30	1.59	1.47	11.2	213.20	3.25	1.92	11.1	0.00	0.00	0.00	11.1	567.44	8.65
1000	90.53	1.38	0.82	11.2	139.73	2.13	1.13	11.2	84.62	1.29	1.45	11.2	227.63	3.47	2.15	11.1	101.02	1.54	0.77	11.1	643.54	9.81
1100	89.22	1.36	0.82	11.2	139.07	2.12	1.13	11.2	120.05	1.83	1.69	11.2	217.14	3.31	2.06	11.1	107.58	1.64	0.82	11.1	673.06	10.19
1200	88.56	1.35	0.81	11.2	134.48	2.05	1.16	11.2	129.23	1.97	1.70	11.2	213.20	3.25	1.99	11.1	102.99	1.57	0.76	11.1	668.46	10.26
1300	87.90	1.34	0.61	11.2	127.26	1.94	0.93	11.2	142.35	2.17	1.68	11.2	190.90	2.91	1.76	11.1	103.65	1.58	0.70	11.1	652.06	9.94
1400	83.31	1.27	0.76	11.3	137.76	2.10	1.11	11.3	167.28	2.55	1.90	11.3	219.76	3.35	2.08	11.2	146.94	2.24	1.10	11.2	755.06	11.51
1500	80.69	1.23	0.72	11.3	146.29	2.23	1.18	11.3	163.34	2.49	1.92	11.3	225.01	3.43	2.08	11.2	146.94	2.24	1.14	11.2	762.27	11.62
1600	79.38	1.21	0.72	11.3	158.75	2.42	1.21	11.3	152.85	2.33	1.80	11.3	236.82	3.61	2.16	11.2	145.63	2.22	1.05	11.2	773.42	11.79
1700	72.75	1.11	0.59	11.2	120.31	1.83	0.74	11.2	133.56	2.04	1.25	11.2	226.98	3.46	1.99	11.2	132.58	2.02	2.02	11.2	686.18	10.46
1800	69.86	1.07	0.61	11.2	133.82	2.04	827.40	11.2	128.71	1.96	1.28	11.2	256.76	3.46	2.03	11.2	148.52	2.26	2.26	11.2	737.67	10.79
1900	72.36	1.10	0.58	11.2	160.46	2.45	1.16	11.2	199.03	3.03	1.47	11.2	256.76	3.91	2.23	11.2	199.03	3.03	3.03	11.2	887.63	13.53
2000	72.36	1.10	0.58	11.1	72.36	1.10	0.58	11.1	160.46	2.45	1.16	11.1	256.76	3.91	2.23	11.1	199.03	3.03	3.03	11.1	760.96	11.60
2100	75.44	1.15	0.56	11.1	155.60	2.37	1.13	11.1	119.65	1.82	1.56	11.1	245.93	3.75	2.10	11.2	179.55	2.74	1.36	11.2	776.18	11.83
2200	66.32	1.01	0.64	11.1	148.78	2.27	1.18	11.1	119.46	1.82	1.61	11.1	237.73	3.62	2.19	11.2	169.25	2.58	1.41	11.2	741.54	11.30
2300	62.32	0.95	0.54	11.1	137.96	2.10	1.06	11.1	117.49	1.79	1.55	11.1	225.80	3.44	2.10	11.2	140.38	2.14	1.28	11.2	683.95	10.43
2400	62.32	0.95	0.54	11.1	111.52	1.70	0.98	11.1	125.82	1.92	1.58	11.1	212.08	3.23	2.09	11.2	128.64	1.96	1.25	11.2	640.39	9.76

Fig. 2.7-2 Examples of Record Sheets for Power Demand

Source: PPL

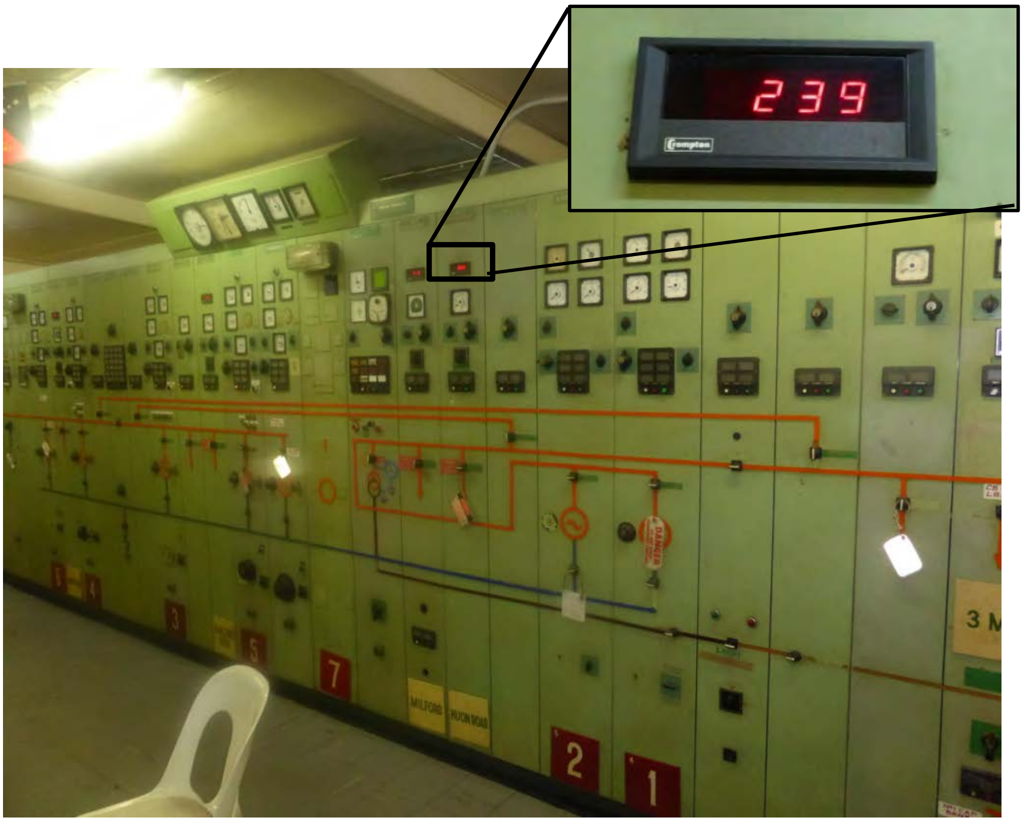


Fig. 2.7-3 Example of Ampere Meter on 11kV Distribution Board (Milford S/S)

2.7.2 Power Demand on each Distribution Feeder

Power demand in 2014 by each feeder are shown below. Moreover, a detailed graph of power demand per feeder are shown in Appendix B-6.

(1) Power demand per feeder (Maximum, Average)

Maximum power demand of Taraka S/S and Milford S/S by each feeder are shown in Fig. 2.7-4, Table 2.7-2 and Table 2.7-3. Average power demand of Taraka S/S and Milford S/S by each feeder are shown in Table 2.7-4 and Table 2.7-5.

The changing by the season seems a few. And the biggest amount of power demand is February 2014 (6.45 MW: Feeder No. 4).

Fig. 2.7-4 indicates that any characteristic pattern does not appear with regard to changes in the load curve through one year.

Further Fig. 2.7-5 indicates that there is large difference for load of each power D/L and there is at most about 2× of differential. This difference should be improved.

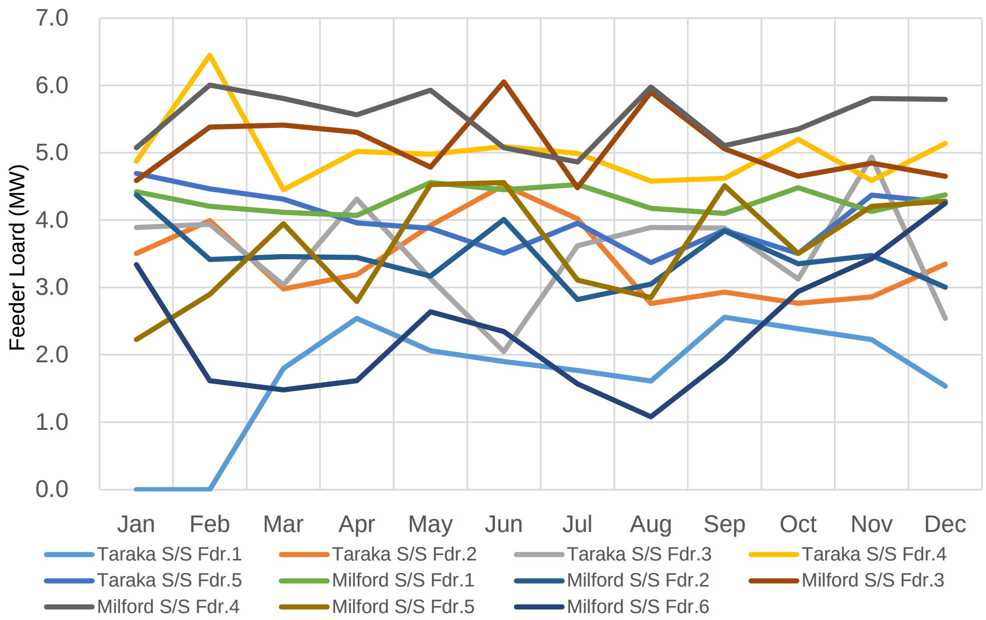


Fig. 2.7-4 Maximum Power Demand per Feeder in 2014

Source: PPL Material arranged by JICA Study Team

Table 2.7-2 Maximum Power Demand per Feeder in 2014 (1)

(Unit: MW)

	Taraka S/S						Nadzab S/S Fdr.1	Milford S/S Subtotal	Total[2]
	Fdr.1	Fdr.2	Fdr.3	Fdr.4	Fdr.5	Sub total[3]			
January	-	3.51	3.89	4.88	4.70	16.97	0.00	24.02	41.00
February	-	3.99	3.94	6.45	4.47	18.85	0.00	23.52	42.37
March	1.80	2.98	3.04	4.45	4.31	16.58	0.47	24.22	41.27
April	2.54	3.19	4.31	5.02	3.96	19.02	0.99	22.79	42.80
May	2.06	3.92	3.13	4.98	3.88	17.97	0.35	25.61	43.93
June	1.90	4.52	2.05	5.09	3.51	17.07	0.84	26.49	44.40
July	1.77	4.02	3.62	4.99	3.96	18.35	0.98	21.37	40.70
August	1.61	2.76	3.89	4.58	3.37	16.22	0.59	23.03	39.84
September	2.56	2.93	3.89	4.62	3.85	17.84	0.46	24.56	42.85
October	2.39	2.77	3.13	5.20	3.51	16.99	0.81	24.28	42.08
November	2.23	2.86	4.94	4.59	4.37	18.98	0.41	25.90	45.29
December	1.54	3.35	2.54	5.14	4.26	16.83	0.92	13.56	31.31
Max.	2.56	4.52	4.94	6.45	4.70	19.02	0.99	26.49	46.50
Ave.	2.04	3.40	3.53	5.00	4.01	17.64	0.57	23.28	41.49

Source: PPL Material arranged by JICA Study Team

Table 2.7-3 Maximum Power Demand per Feeder in 2014 (2)

(Unit: MW)

	Milford S/S						
	Fdr.1	Fdr.2	Fdr.3	Fdr.4	Fdr.5	Fdr.6	Sub-total[4]
January	4.42	4.38	4.59	5.08	2.23	3.34	24.02
February	4.21	3.41	5.38	6.01	2.90	1.62	23.52
March	4.12	3.46	5.41	5.81	3.95	1.48	24.22
April	4.07	3.45	5.30	5.56	2.79	1.62	22.79
May	4.56	3.17	4.79	5.93	4.53	2.64	25.61
June	4.45	4.01	6.05	5.08	4.56	2.35	26.49
July	4.53	2.82	4.48	4.86	3.11	1.57	21.37
August	4.18	3.05	5.90	5.98	2.85	1.08	23.03
September	4.10	3.84	5.06	5.11	4.51	1.94	24.56
October	4.48	3.35	4.65	5.35	3.51	2.94	24.28
November	4.13	3.48	4.85	5.81	4.21	3.43	25.90
December	4.38	3.00	4.65	5.79	4.28	4.25	13.56
Max.	4.56	4.38	6.05	6.01	4.56	4.25	26.49
Ave.	4.30	3.45	5.09	5.53	3.62	2.35	23.28

Source: PPL Material arranged by JICA Study Team

2 Total (MW) = Sub Total [Taraka S/S](MW) + Nadzab S/S/ Fder.1 (MW) + Subtotal [Milford S/S](MW)
3 Subtotal (MW) = Taraka S/S (Fdr.1 (MW) + Fdr.2 (MW) + Fdr.3 (MW) + Fdr.4 (MW) + Fdr.5 (MW))
4 Subtotal (MW) = Milford S/S/(Fdr.1 (MW) + Fdr.2 (MW) + Fdr.3 (MW) + Fdr.4 (MW) + Fdr.5 (MW) + Fdr.6 (MW))

Table 2.7-4 Average Power Demand per Feeder in 2014 (Taraka S/S)

(Unit: MW)

	Fdr.1	Fdr.2	Fdr.3	Fdr.4	Fdr.5	Max.
January	-	2.95	2.72	3.18	3.79	3.79
February	-	3.09	2.53	4.06	3.16	4.06
March	1.15	2.15	1.16	3.31	3.04	3.31
April	1.31	2.05	1.11	3.26	2.53	3.26
May	1.35	2.10	1.08	3.45	2.46	3.45
June	1.09	1.96	1.05	3.24	2.27	3.24
July	0.99	1.93	1.16	3.19	2.23	3.19
August	1.04	1.94	1.37	3.19	2.34	3.19
September	1.13	2.02	1.06	3.20	2.38	3.20
October	1.14	1.96	1.09	3.33	2.13	3.33
November	1.04	1.97	1.29	3.44	1.39	3.44
December	1.03	1.98	1.01	3.21	1.00	3.21
Max.	1.35	3.09	2.72	4.06	3.79	4.06
Ave.	1.13	2.17	1.39	3.34	2.39	3.34

Source: PPL Material arranged by JICA Study Team

Table 2.7-5 Average Power Demand per Feeder in 2014 (Milford S/S)

(Unit: MW)

	Fdr.1	Fdr.2	Fdr.3	Fdr.4	Fdr.5	Fdr.6	Max.
January	2.39	1.81	2.38	2.49	1.21	1.25	2.49
February	2.68	1.67	2.75	2.90	1.64	0.63	2.90
March	2.45	1.88	2.78	2.63	1.59	0.73	2.78
April	2.37	1.87	2.68	2.78	1.56	1.12	2.78
May	2.77	1.80	2.79	2.68	1.77	0.87	2.79
June	2.18	1.23	3.28	2.58	2.29	1.49	3.28
July	2.49	1.54	2.33	2.58	1.52	0.77	2.58
August	2.54	1.67	2.72	2.89	1.70	0.77	2.89
September	2.38	1.66	2.44	2.71	1.79	0.78	2.71
October	2.44	1.78	2.54	2.95	1.82	1.04	2.95
November	2.57	1.85	2.45	3.12	2.02	1.98	3.12
December	2.60	1.54	2.31	3.00	2.21	1.91	3.00
Max.	2.77	1.88	3.28	3.12	2.29	1.98	3.28
Ave.	2.49	1.69	2.62	2.78	1.76	1.11	2.78

Source: PPL Material arranged by JICA Study Team

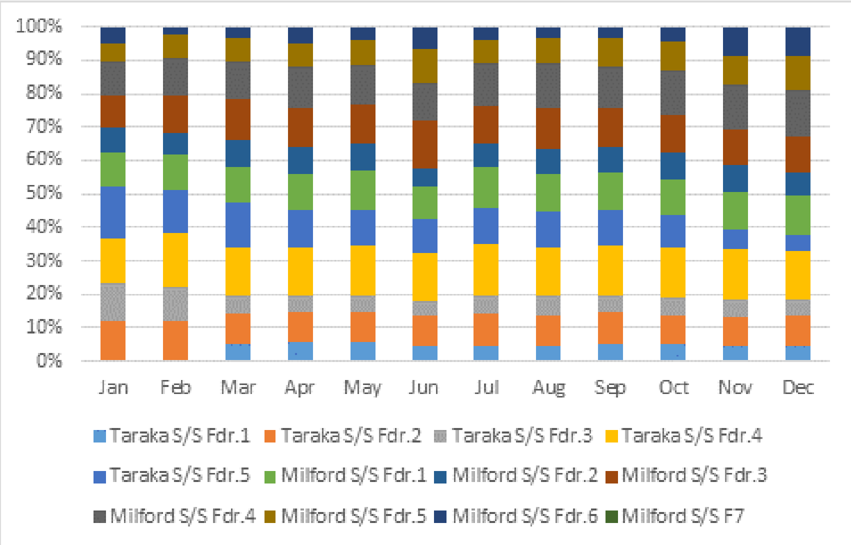


Fig. 2.7-5 Ratio of Average Power Demand per Feeder in 2014

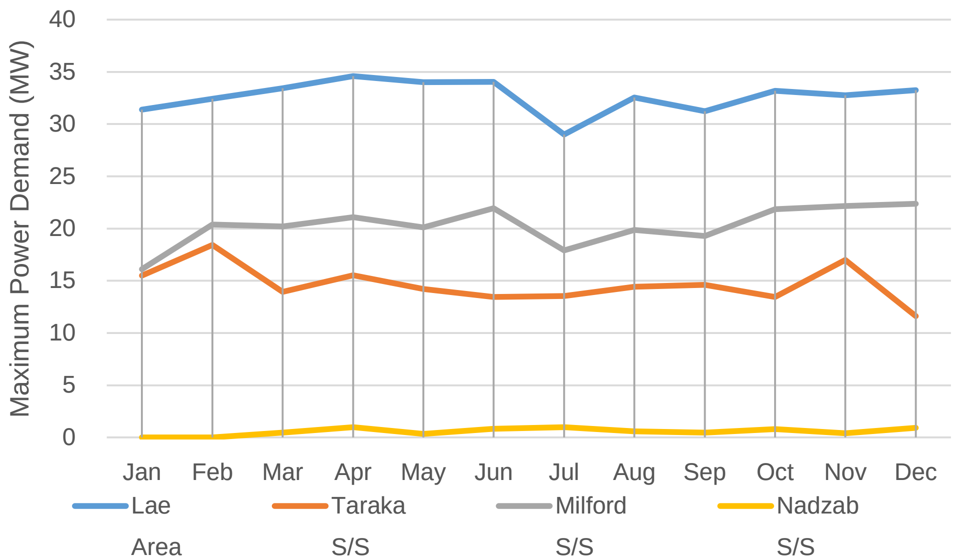
Source: PPL Material arranged by JICA Study Team

(2) Coincident maximum power demand per substation in the Lae area

Coincident maximum power demand in the Lae area and Ratio of Coincident average power demand per substation in the Lae area are shown in Fig. 2.7-6 and Fig. 2.7-7.

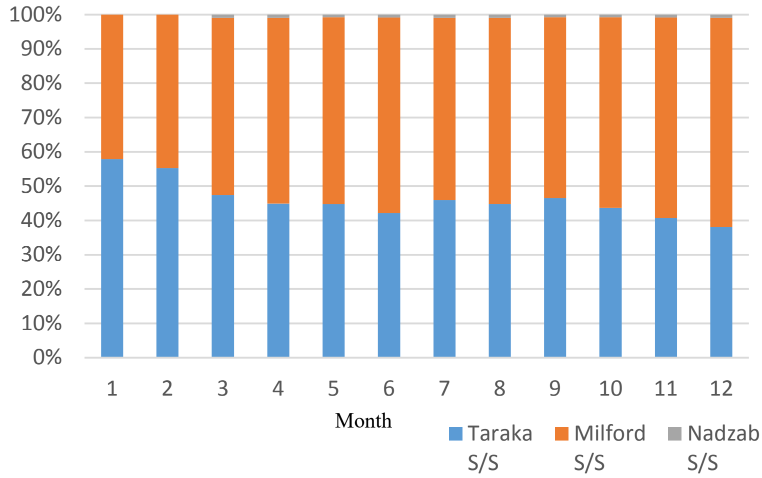
Coincident maximum power demand by substation and Coincident maximum power demand in the Lae area are shown in Table 2.7-6 and Table 2.7-7.

Fig. 2.7-7 indicate that the utilization rate of the transformer in Taraka substation is about 38% and about 50% in the Milford substation.



Source: PPL Material arranged by JICA Study Team

Fig. 2.7-6 Coincident Maximum Power Demand in the Lae Area (2014)



Source: PPL Material arranged by JICA Study Team

Fig. 2.7-7 Ratio of Coincident Average Power Demand per Substation in the Lae Area (2014)

Table 2.7-6 Coincident Maximum Power Demand by Substation in 2014

(Unit: MW)

	Coincident maximum power demand			Average of Coincident power demand		
	Taraka S/S	Milford S/S	Nadzab S/S	Taraka S/S	Milford S/S	Nadzab S/S
January	15.49	16.11	0.00	12.59	9.18	-
February	18.42	20.40	0.00	12.73	10.29	-
March	13.95	20.21	0.47	10.32	11.22	0.20
April	15.54	21.09	0.99	10.01	12.06	0.20
May	14.22	20.12	0.35	10.33	12.58	0.18
June	13.44	21.94	0.84	9.43	12.76	0.19
July	13.53	17.92	0.98	9.37	10.85	0.19
August	14.44	19.86	0.59	9.81	11.88	0.21
September	14.60	19.28	0.46	9.48	10.76	0.16
October	13.44	21.85	0.81	9.51	12.07	0.17
November	16.99	22.14	0.41	9.06	13.02	0.19
December	11.63	22.36	0.92	8.10	12.97	0.20
Max.	18.42	22.36	0.99	12.73	13.02	0.21
Ave.	14.64	20.27	0.57	10.06	11.64	0.19

Source: PPL Material arranged by JICA Study Team

Table 2.7-7 Coincident Maximum Power Demand in the Lae Area (2014)

(Unit: MW)

	Coincident power demand in Lae	
	Maximum	Average
January	31.37	10.41
February	32.43	13.15
March	33.43	15.84
April	34.58	21.22
May	34.02	20.25
June	34.04	22.34
July	29.01	18.42
August	32.54	21.77
September	31.23	18.94
October	33.18	18.70
November	32.77	21.97
December	33.24	20.79
Max.	34.58	22.34
Ave.	32.65	18.65

Source: PPL Material arranged by JICA Study Team

(3) Diversity factor between feeders in the Lae area

The diversity factor between feeders was calculated by the following definitions.
Diversity factor between feeders is shown in Table 2.7-8.

Diversity factor between feeders in the Lae area = Total of maximum power demand per feeder5 [MW]/ Coincident maximum power demand in Lae6 [MW]***

Table 2.7-8 Diversity Factor between Feeders

	Total of maximum power demand per feeder [MW]*	Coincident maximum power demand in Lae [MW]**	Diversity factor */**
January	41.00	31.37	1.31
February	42.37	32.43	1.31
March	41.27	33.43	1.23
April	42.80	34.58	1.24
May	43.93	34.02	1.29
June	44.40	34.04	1.30
July	40.70	29.01	1.40
August	39.84	32.54	1.22
September	42.85	31.23	1.37
October	42.08	33.18	1.27
November	45.29	32.77	1.38
December	31.31	33.24	0.94
Max.	46.50	34.58	1.40
Ave.	41.49	32.65	1.27

Source: JICA Study Team

5 Refer to Table 2.7-2 and Table 2.7-3.
6 Refer to Table 2.7-7.

From the above-mentioned, diversity factor 1.27 of average should be adopted in Section 4.3.

2.7.3 Load Curve Pattern

The patterns of Load curve are shown as follows:

(i)	Daily Load Carve Pattern by feeders (Taraka S/S)	Fig. 2.7-8
(ii)	Daily Load Carve Pattern by feeders (Milford S/S)	Fig. 2.7-9
(iii)	Daily Load Carve Pattern (Taraka S/S and Milford S/S)	Fig. 2.7-10
(iv)	Daily Load Carve Pattern in the Lae area	Fig. 2.7-11

The daily load carve pattern shows quite different pattern between the use of electricity of the load of Milford S/S and Taraka S/S. The load of Milford S/S is seen by the load curve on Monday - Friday for industrial area. The load of Taraka S/S is seen by the lighting peak at 18-19 o'clock for residential area.

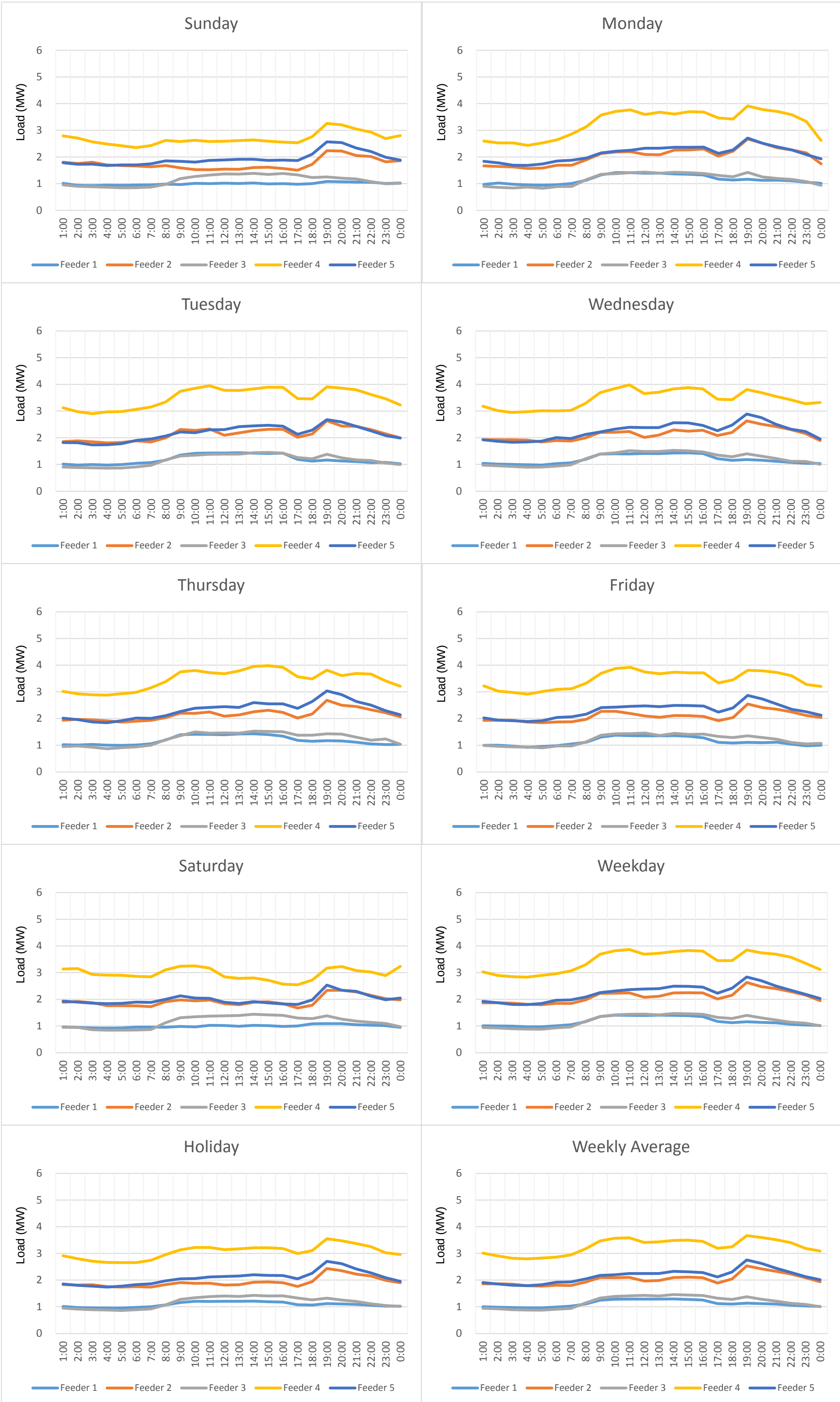


Fig. 2.7-8 Daily Load Carve Pattern by Feeders (Taraka S/S)

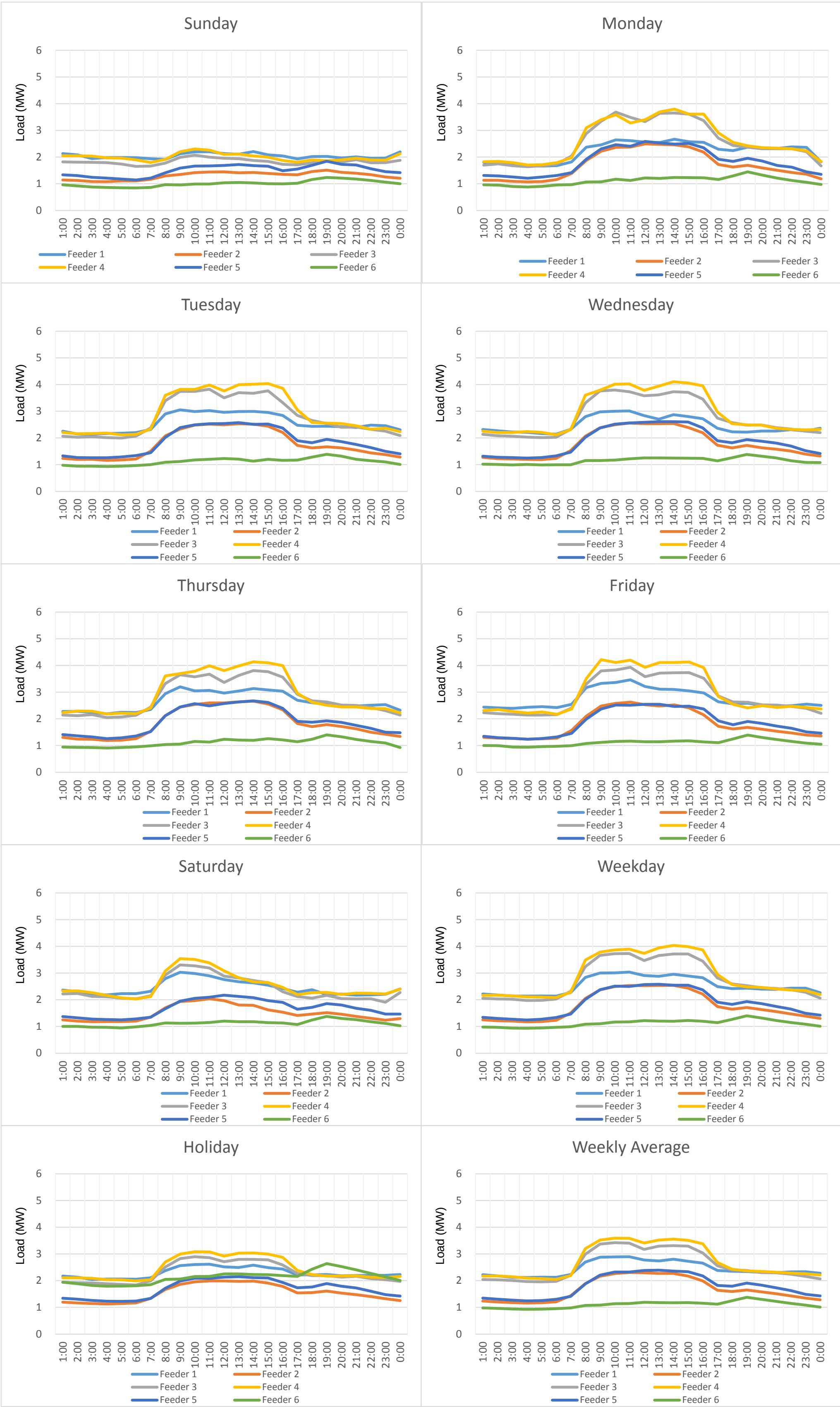


Fig. 2.7-9 Daily Load Carve Pattern by Feeders (Milford S/S)

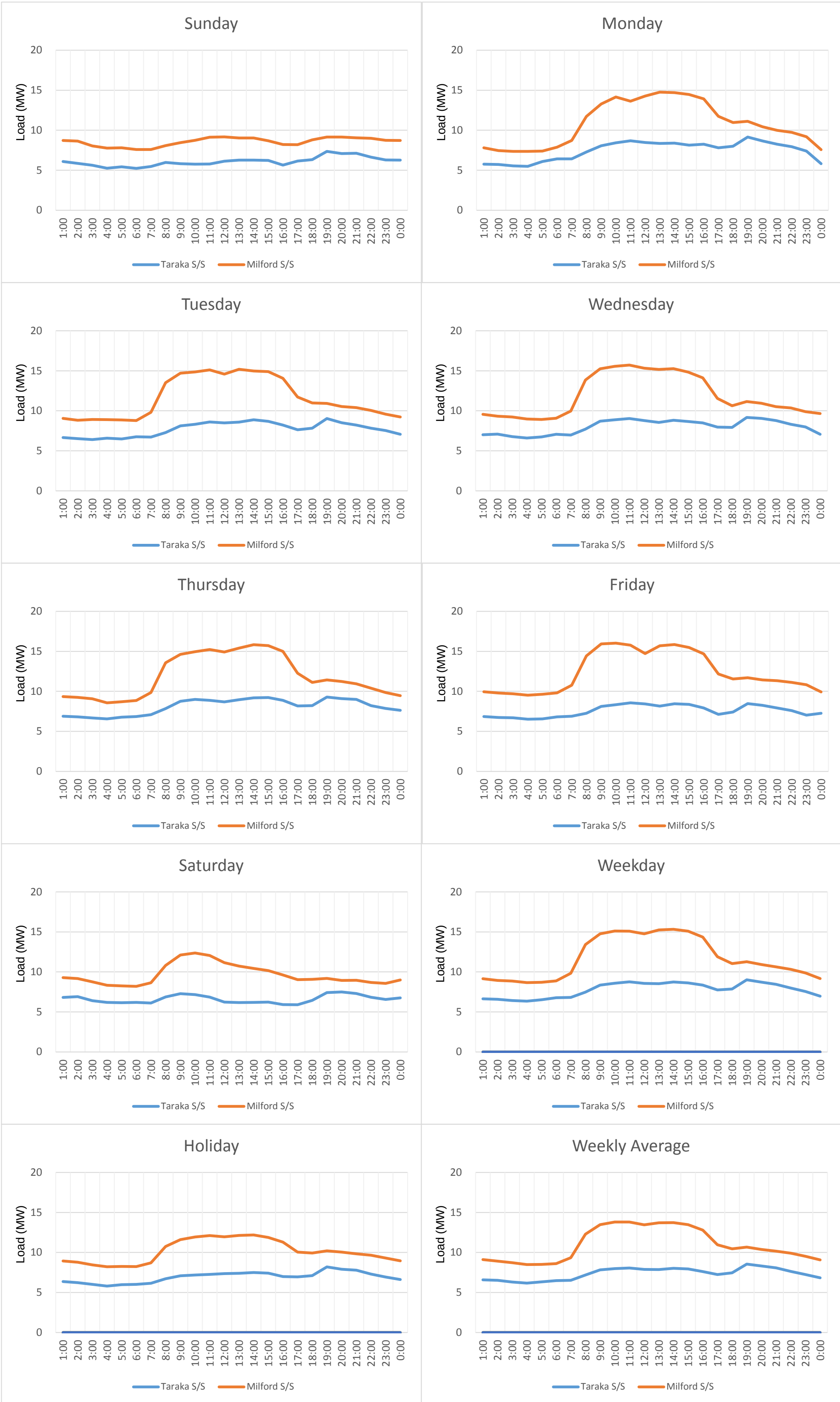


Fig. 2.7-10 Daily Load Carve Pattern (Taraka S/S and Milford S/S)

Fig. 2.7-11 Daily Load Carve Pattern in the Lae Area

2.8 POWER QUALITY MEASUREMENT

2.8.1 Purpose

According to the past report[7], harmonics were measured in Lae city. Since the actual condition of harmonics must be assessed, the purpose of this measurement is to determine the effect of the harmonics (low order to high frequency) in Lae city. In addition, a long-term power quality measurement in Lae city was performed.

Power quality measurement was performed in the following schedule

- ♦ First survey (Nov/2014-Dec/2014) .... Site inspection, Selection of measuring point
- ♦ Second survey (Jan/2015-Mar/2015) ..... Implementation and analysis of the preliminary measurement
  Installation of measuring instruments for the long-term measurement (4 weeks)
- ♦ Third survey (Apr/2015-May/2015) ...... Data collection and analysis of the long-term measurement

In the first survey, a site inspection was performed. The location of measuring points such as VTs and CTs and the location where the measuring instruments were installed were confirmed.

The second survey mainly involved preliminary measurement. The main purpose was to select three D/Ls for long-term measurement. During the preliminary measurement, the harmonic current of each D/L was measured over a period of 2 to 8 days. We planned to install the measuring instruments on D/Ls with a harmonic current exceeding that of the other D/Ls.

Consequently, each measured harmonic current of D/L was relatively similar. Accordingly, we installed the measuring instruments on Milford substation Feeder 1, where the harmonics were measured according to the past report, Milford substation Feeder 2 and Taraka substation Feeder 4 for the long-term 4-week measurement. Milford substation Feeder 2 and Taraka substation Feeder 4 supply industrial areas which may be sources of harmonics. In this section, each feeder number is abbreviated. For example, Milford substation Feeder 1 is abbreviated to M1 and Taraka substation Feeder 4 is abbreviated to T4.

In the third survey, we collected the data from measuring instruments and analyzed it.

2.8.2 Method and Feeder Selection of Long-Term Measurement

(1) Method of Measurement

Table 2.8-1 shows the measurement condition. The feeder in the Nadzab substation could not be measured due to the lack of VTs or CTs. Three feeders can be measured at the same time because we have three measuring instruments.

Fig. 2.8-1 shows the installation of measuring instruments in Taraka substation

7 The final report on the Detailed Planning Survey on the Project for the Lae Area Power Development Master Plan

Table 2.8-1 Condition of Measurement

Item	Content	Remarks
Object	Distribution network in the Lae area	5 feeders in the Taraka substation, 6 feeders in the Milford substation (One feeder in the Nadzab substation could not be measured)
Measuring points at the same time	Three points	
Measuring voltage	11kV	The voltage and current of the 11kV feeder is measured at the secondary voltage of VT, with a transformer ratio of 11kV/110V and secondary CT current. In the Milford substation, the voltage is measured by the VT installed in the 11kV bus. In the Taraka substation, the voltage is measured by the VT installed in each feeder.
Measuring instrument	Power Quality Analyzer Hioki PW3198 × 3 Clamp Sensor CT9694	Capable of measuring harmonics and 3-phase power
Wiring	3P3W3M (3 voltage/3 current)	Power was measured by 3-phase voltage and current

Source: JICA Study Team

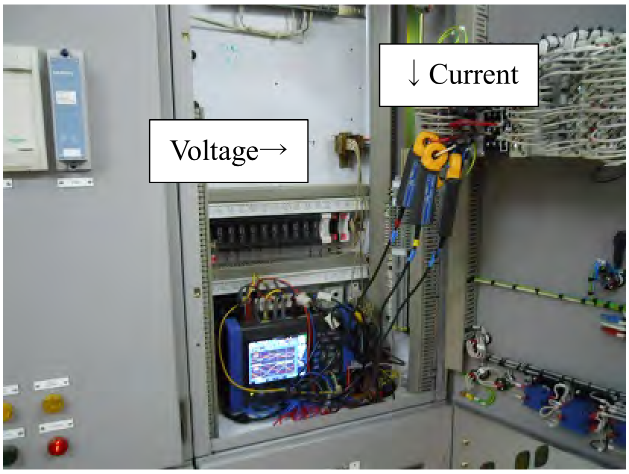
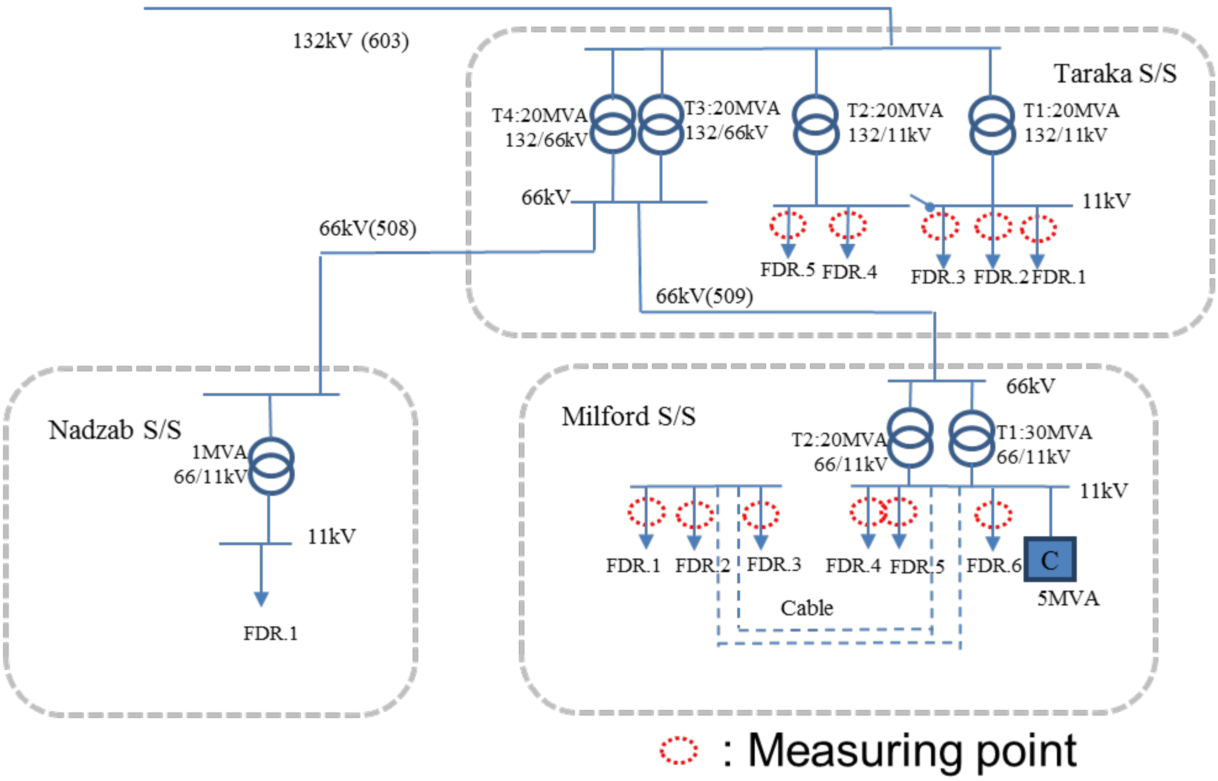


Fig. 2.8-1 Installation of a Measuring Instrument in the Taraka Substation

(2) Measuring point

Fig. 2.8-2 shows the measuring points at the secondary side VT and CT.



Source: JICA Study Team

Fig. 2.8-2 Measuring Point

(3) Outline of Preliminary Measurement

To select the three D/Ls for long-term measurement, all the D/Ls were measured. The duration of the preliminary measurement was two to eight days. We planned to install measuring instruments on the D/Ls with a higher harmonic current compared to the other D/Ls.

The preliminary measurement schedule is shown in Fig. 2.8-3.

Date		12-Feb	13-Feb	14-Feb	15-Feb	16-Feb	17-Feb	18-Feb	19-Feb	20-Feb	21-Feb	22-Feb	23-Feb	24-Feb	25-Feb	26-Feb	27-Feb	28-Feb	1-Mar	2-Mar	3-Mar	4-Mar
Day		Thu	Fri	Sat	Sun	Mon	Tue	Wed	Thu	Fri	Sat	Sun	Mon	Tue	Wed	Thu	Fri	Sat	Sun	Mon	Tue	Wed
Milford	1	#	#	#	#	#	#	#	#													
	2	#	#	#	#	#	#	#	#													
	3	#	#	#	#	#	#	#	#	Data collection and review												
	4													#	#	#	#					
	5													#	#	#	#					
	6													#	#	#	#					
Taraka	1																	#	#			
	2																			#	#	
	3																	#	#			
	4																			#	#	
	5																			#	#	
Remarks			*1		*1			*1	*1					*1	*1	*1,*2	*1,*2	*1,*3	*1,*3	*4	*4	

*1 Some values which could not be measured accurately due to the outage are not adopted in order to review harmonic wave and the power quality and in normal operation.
*2 measured from 11:00 to 11:00 of the next day
*3 measured from 15:00 to 15:00 of the next day
*4 measured from 17:00 to 17:00 of the next day

Source: JICA Study Team

Fig. 2.8-3 Measuring Schedule

Basically three measuring instruments have the same setting. Fig. 2.8-4 shows the setting of the measuring instrument installed in the Milford substation. When measuring in the Taraka substation, the CT ratio of 123ch, which means 3-phase, is changed from 80 to 1200 because the CT ratio in the Taraka substation is 1200/1A, unlike that in the Milford substation (400/5A).

	123ch	4ch
Wiring	3P3W3M	OFF
Clamp	9694	9661
U Range	600.00 V	600.00 V
PT Ratio	0100.00	0001.00
I Range	50.000 A	500.00 A
CT Ratio	0080.00	0001.00

U din	10.000kV
Frequency	50Hz
Sync Source	U1
URMS Type	LINE-LINE
Harm Calc	U,I,P:ALL % of ...
THD Type	THD_F
PF Type	PF
Flicker	Delta V10
Recording Items	ALL DATA
TIME PLOT Interval	1 min
Disp COPY Interval	1 hour
Time Start	OFF
Repeat Record	1 Day
Record Start Time	00:00:00
Record End Time	00:00:00
Repeat Number	30
Serial No.	141216576
PW3198 Version	1.06

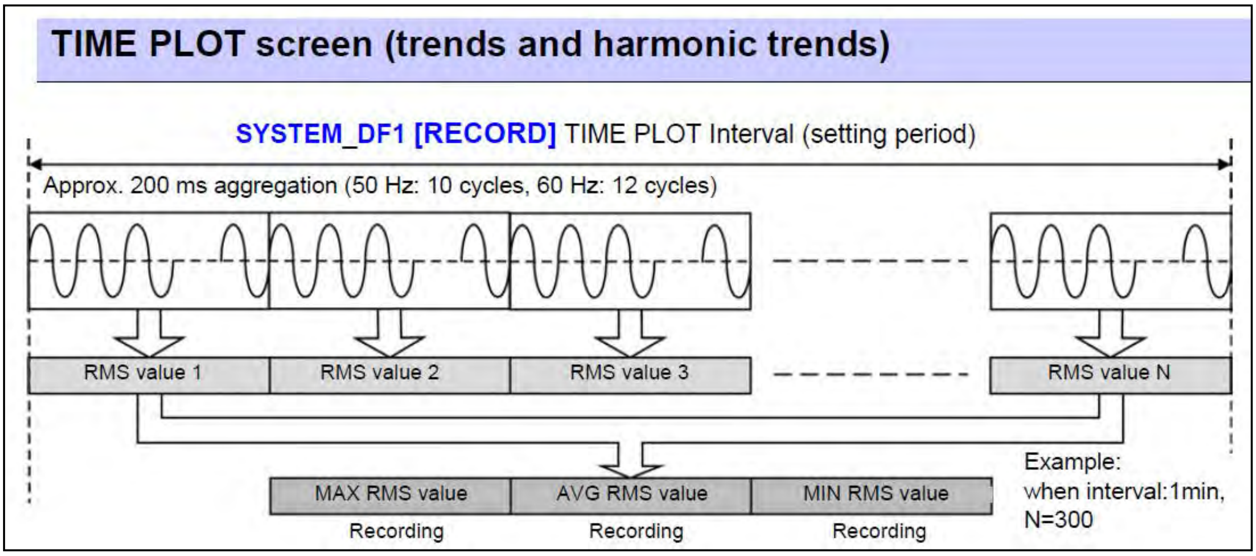
Source: JICA Study Team

Fig. 2.8-4 Preliminary Measurement Condition

We explain the TIME PLOT interval, which is one of the setting conditions with Fig. 2.8-5.

The measuring instruments are used to calculate root mean square (RMS) values of voltage and current per 50Hz 10 cycles (= 200ms). RMS values of 1, 2 and 3 in Fig. 2.8-5 mean the calculated RMS values. Accordingly, the measuring instruments select the Max. and Min. values and calculate the AVG value per period, which is known as the TIME PLOT interval.

Where the TIME PLOT interval is set at 1min, the number of RMS values is 300 (1min /200ms=300). The measuring instruments record MAX. and MIN. values within 300 values and calculate the AVG value by the 300 values. The graphs shown in this report and its appendix comprise MAX (Blue color), AVG (Green color) and MIN (Red color) values. These values are calculated by the process mentioned above.



Source: Hioki PW3198 Instruction Manual

Fig. 2.8-5 TIME PLOT Interval

(4) Result of Preliminary Measurement

Before the preliminary measurement result is shown, we explain the total harmonic distortion factor, which is the indicator of harmonics and its criteria. Many kinds of criteria are referred to in this report, such as those at target level, those regulated strictly and so on. Each has importance but in this report, we refer to all of them as the same word criteria to simplify the discussion. The meaning of the criteria is explained in each case if necessary.

The total harmonic voltage or current distortion factor is the ratio of the total harmonic component to the size of the fundamental wave expressed as a percentage using the following equation:

$$\mathrm{THD} = \frac{\sum(from\ 2nd\ order)^2}{fundamental\ wave} \times 100[\%]$$

(the measuring instrument calculated from 2nd to 50th order)

This value can be monitored to assess waveform distortion for each item, providing a yardstick that indicates the extent to which the total harmonic component distorts the fundamental waveform. In this report, the total harmonic voltage distortion factor is expressed as Uthd and the total harmonic current distortion factor as Ithd.

There is no criteria for Ithd in PNG. Accordingly, we review the measured Ithd compared to the criteria of another country. The Institute of Electrical and Electronics Engineers, Inc. (IEEE) Std 519-2014 describes the criteria whereby Ithd should be limited to 5.0% for systems rated 120V through 69kV provided that $I_{SC}/I_L<20$ (I_{SC} = maximum short-circuit current, I_L=maximum demand load current). Moreover, the stay rate of the Ithd within the value of the criteria is described as follows:

Daily 99th percentile very short time (3 s) harmonic currents should be less than 2.0× the value of the criteria.

Or Weekly 99th percentile short time (10 min) harmonic currents should be less than 1.5× the value of the criteria.

Or Weekly 95th percentile short time (10 min) harmonic currents should be less than the value of the criteria.

In this report, we apply 5% as the criteria of Ithd.

1) The preliminary measurement result

Table 2.8-2 shows the measured Ithd of each feeder. As mentioned in the Remarks, Ithd was calculated except for the values measured during outages. This reason is described later. Fig. 2.8-6 and Fig. 2.8-7 show the Ithd as of 17 February. Only the graph of the first phase (CH1) is shown in this report as representative information.

Table 2.8-2 Ithd of each Feeder

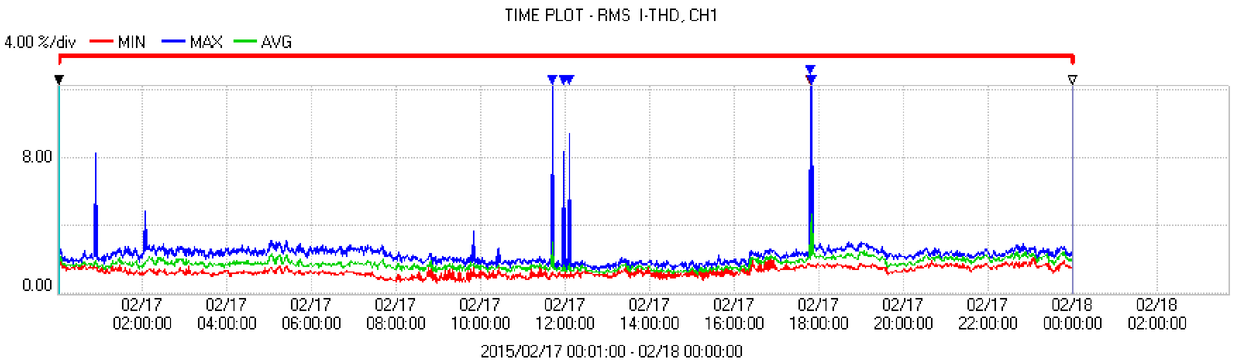
Feeder	M1	M2	M3	M4	M5	M6	T1	T2	T3	T4	T5
Day	17-Feb	17-Feb	17-Feb	24-Feb	24-Feb	24-Feb	1-Mar	2-Mar	1-Mar	2-Mar	2-Mar
Ithd [%]	**2.1**	**1.6**	**1.9**	**1.6**	**1.7**	**1.6**	**1.6**	**1.5**	**1.7**	**1.8**	**1.8**
Remarks				*1	*1	*1	*1,*2	*3	*1,*2	*3	*3

*1: Ithd is calculated except for the values measured during outages
*2: Measured from 15:00 to 15:00 the following day
*3: Measured from 17:00 to 17:00 the following day

Source: JICA Study Team

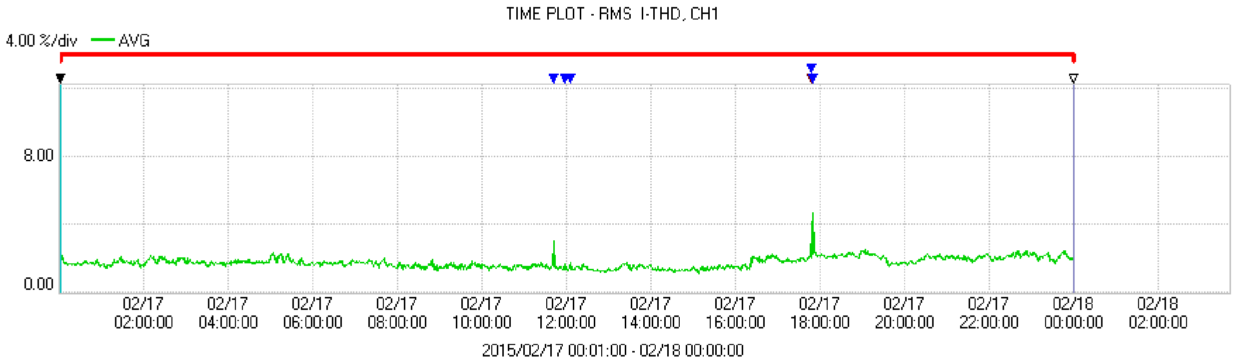
As shown in this table, the Ithd of each feeder is 1.5 to 2.1%, which is lower than 5.0%. According to the preliminary measurement, the effect of harmonic current is not considered problematic. However we evaluate the effect of the harmonics based on the result of long-term measurement due to the short duration of preliminary measurement.

Fig. 2.8-6 shows all the values: red is MIN, blue is MAX and green is AVG. Conversely, Fig. 2.8-7 shows only the green (AVG). The short-term harmonics, with duration lasting 100ms ~ several seconds was measured in Fig. 2.8-6. These short-term harmonics occurred several times per day. Some MAX values exceeded 10% instantaneously. The harmonics referred to previously are considered short-term harmonics and are covered in Section 2.5.3.



Source: JICA Study Team

Fig. 2.8-6 Ithd at M1 on 17 February (MIN, MAX, AVG)



Source: JICA Study Team

Fig. 2.8-7 Ithd at M1 on 17 February (AVG)

Information acquired from the preliminary measurement is summarized.

2) Power Factor of the Distribution Line

Table 2.8-3 shows the power factor of the each feeder acquired from the preliminary measurement.

Table 2.8-3 Power Factor (PF) of each Feeder

Feeder	M1	M2	M3	M4	M5	M6	T1	T2	T3	T4	T5
PF	**0.84**	**0.87**	**0.81**	**0.84**	**0.86**	**0.85**	**0.84**	**0.86**	**0.87**	**0.83**	**0.90**
	PF is calculated except for the values measured during outages The error range may be ±0.02 or more due to the short measuring term										

Source: JICA Study Team

If a more accurate PF is necessary, PF should be calculated from the longer term measurement. This preliminary measurement only shows that the PF in Lae city is about 0.85.

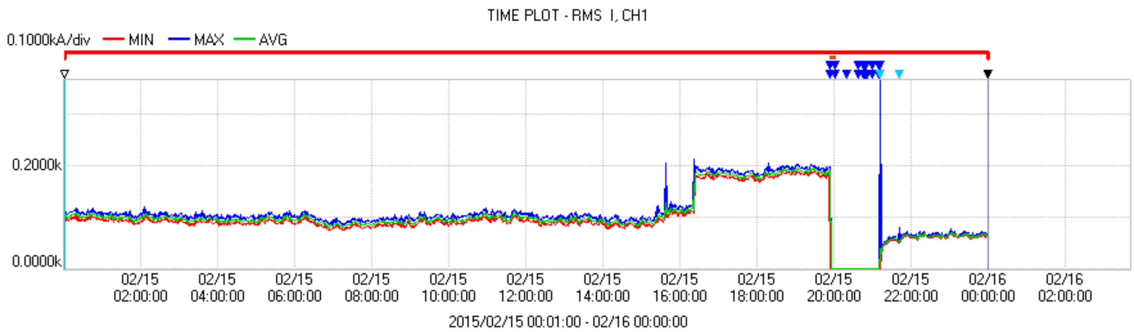
3) Effect of the Outage

Fig. 2.8-8 and Fig. 2.8-9 show the current and Ithd at M1 on 15 February. Fig. 2.8-8 shows an outage occurred at M1 between 20:00 and 21:00 on 15 February. During the outage, Fig. 2.8-9 shows that the value of the harmonic distortion factor rose excessively compared to that in the other time zone.

The following is considered to occur during the outage:

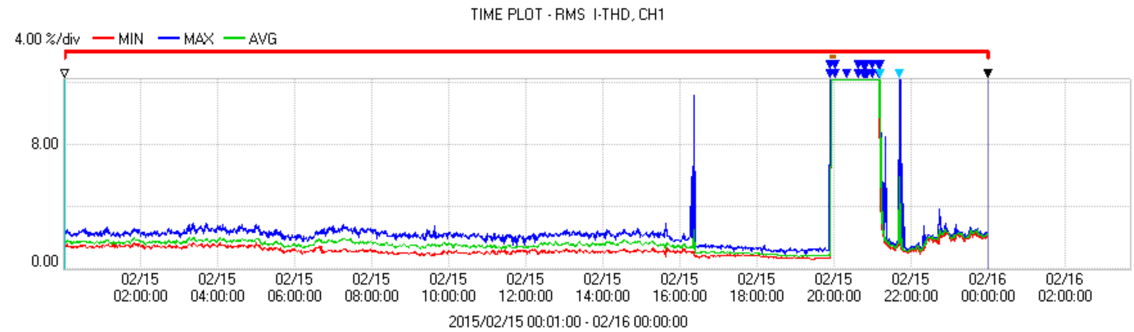
A little current of each wavelength is usually induced on the CT circuit in addition to that of 50Hz. During normal operation, the current of 50Hz occupies a significant proportion of the CT circuit current compared to the current of each wavelength. Accordingly, the total harmonic factor is small. However, in case of outages, the current of 50Hz does not flow to the CT circuit and the current of each wavelength occupies a larger proportion than that during normal operation. Accordingly, it is estimated that the value of the harmonic distortion factor rises excessively during outages.

Accordingly, the values measured during outages are regarded as abnormal and need to be eliminated.



Source: JICA Study Team

Fig. 2.8-8 Current at M1 on 15 February



Source: JICA Study Team

Fig. 2.8-9 Ithd at M1 on 15 February

(5) Selection of the distribution line

As mentioned above, there was little difference between the Ithd measured in each feeder and it was smaller than the criteria during the preliminary measurement. Because there was little difference between the Ithd measured in each feeder, we installed measuring instruments on M1, where harmonics were measured according to the past report, M2 and T4 for the long-term measurement of 4 weeks. M2 and T4 supply industrial areas which may potentially be sources of harmonics.

2.8.3 Result of Long-Term Measurement

(1) Outline of Long-Term Measurement

The long-term measurement was performed over 4 weeks from 12:00 5 March, 2015 (Thu.) to 12:00 2 April, 2015 (Thu.).

The measuring values were recorded on the SD card installed in the measuring instruments every week. During the fourth week (26 March (Thu.) ~ 2 April (Thu.)), an extended outage occurred in the Taraka substation at about 2:00 and continued until about 8:30. During the outage, power supply to the measuring instrument was cut off and the internal battery ran out. Accordingly, we didn't acquire the data of T4 from 05:30 to 08:20 on 27 March (Thu.). Because the duration was only three hours and the outage continued in the distribution network at the time, this incident has hardly influenced the result of the long-term measurement. In the appendix, the graph of T4 on the fourth week is separated into two parts due to the outage. One is from 26-27 March and other is from 27 March to 2 April.

During the long-term measurement, harmonics voltage (low order to high frequency), harmonics current (low order to high frequency), voltage, frequency, swells, dips and outage were measured. We showed the result of long-term measurement and reviewed it compared to some criteria.

Basically three measuring instruments have the same setting. Fig. 2.8-10 shows the setting of the measuring instrument installed in T4. When measuring in the Milford substation, the CT ratio of 123ch, which means 3-phases is changed from 1200 to 80 because the CT ratio in the Milford substation is 400/5A, which differs from that in the Taraka substation (1200/1A).

	123ch	4ch
Wiring	3P3W3M	OFF
Clamp	9694	9661
U Range	600.00 V	600.00 V
PT Ratio	0100.00	0001.00
I Range	5.0000 A	500.00 A
CT Ratio	1200.00	0001.00

U din	11.000kV
Frequency	50Hz
Sync Source	U1
URMS Type	LINE-LINE
Harm Calc	U,I,P:ALL % of ...
THD Type	THD_F
PF Type	PF
Flicker	Delta V10
Recording Items	ALL DATA
TIME PLOT Interval	10 min
Disp COPY Interval	1 hour
Time Start	ON
Repeat Record	1 Week
START Time	2015/03/05 12:00
Repeat Number	4
Serial No.	141216576
PW3198 Version	1.06

Source: JICA Study Team

Fig. 2.8-10 Condition in Long-Term Measurement

The measuring points for long-term measurement are the same as for the preliminary measurement shown in Fig. 2.8-2.

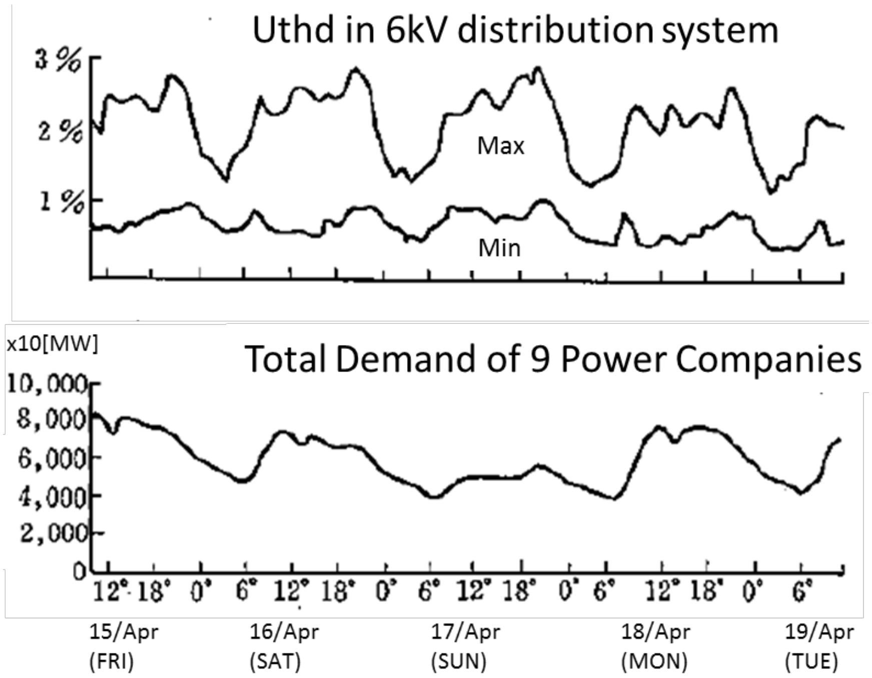
(2) Result of Long-Term Measurement

1) Harmonic voltage (low order)

For the harmonic voltage, we review the measured Uthd. There are no criteria for Uthd in PNG. Accordingly, we review the measured Uthd compared to the criteria of another country.

In Japan, Uthd is limited to 5% in high-voltage systems with a rated voltage range of 600V<V ≦7kV and 3% in ultra-high-voltage systems with a rated voltage range of 7kV<V, as the harmonic environment target level to be maintained in the system. Because the rated voltage in the Lae area distribution network is 11kV, we apply 3% as the criteria of Uthd in this report.

As reference, Fig. 2.8-11 shows Uthd measured in the Japanese distribution network with a rated voltage of 6kV. In Japan, Uthd is about 1~3%.



Source: Electric Technology Research Association Vol. 46 No. 2
"Harmonic and its measures in the power system"

Fig. 2.8-11 Uthd in Japanese 6.6kV Distribution Line in June 1990

IEEE Std 519-2014 describes the criteria whereby Uthd should be limited to 5.0% for systems rated 1kV through 69kV. Moreover, the percentile Uthd within the value of the criteria is described as follows:

Daily 99th percentile very short time (3 s) harmonic voltages should be less than 1.5× the value of the criteria.

Or Weekly 95th percentile short time (10 min) harmonic currents should be less than the value of the criteria.

Table 2.8-4 shows Uthd measured in the long-term measurement. Fig. 2.8-12 and Fig. 2.8-13 show Uthd at Milford S/S 11kV bus in a week.

Table 2.8-4 Total Harmonic Voltage Distortion Factor (Uthd)

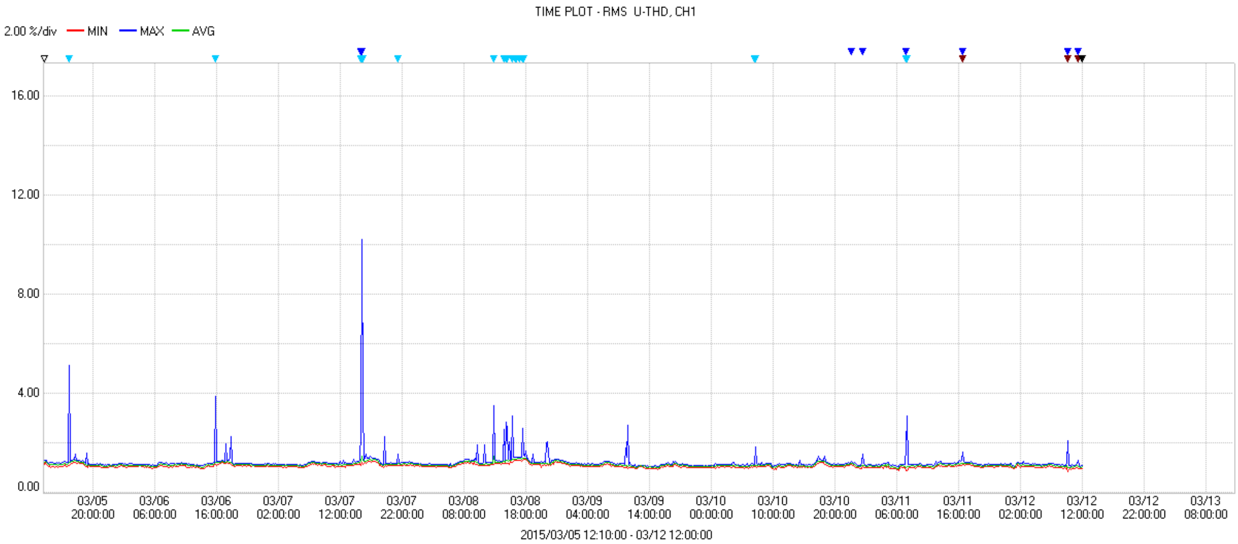
Total harmonic voltage distortion factor (Uthd)		Milford S/S 11kV bus Uthd (%) brackets show the maximum value over one week			Taraka S/S 11kV bus Uthd (%) brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3	CH1	CH2	CH3
1 week	5-Mar	**1.13 (1.49)**	**0.83 (1.30)**	**0.87 (1.37)**	**0.86 (1.18)**	**0.70 (1.07)**	**0.75 (1.13)**
1 week	12-Mar	**1.11 (1.36)**	**0.84 (1.04)**	**0.84 (1.21)**	**0.78 (1.14)**	**0.63 (0.95)**	**0.69 (1.10)**
1 week	19-Mar	**1.08 (2.43)**	**0.80 (2.15)**	**0.82 (2.25)**	**0.78 (2.43)**	**0.66 (2.33)**	**0.69 (2.47)**
1 week	26-Mar	**1.13 (2.02)**	**0.85 (1.70)**	**0.86 (1.84)**	**0.78 (2.13)**	**0.62 (2.00)**	**0.69 (2.14)**

Source: JICA Study Team

As mentioned in the preliminary measurement, Uthd is calculated except for the values measured during outages. In the long-term measurement duration (24 hours × 28 days × 2 measuring points = 1344 hours), the 1299 hours' data is summarized in this Table except for 45 hours during outages. The brackets show the maximum value over one week as reference. Because the measuring instruments installed at M1 and M2 measure the same voltage, the table shows only measured values at M1.

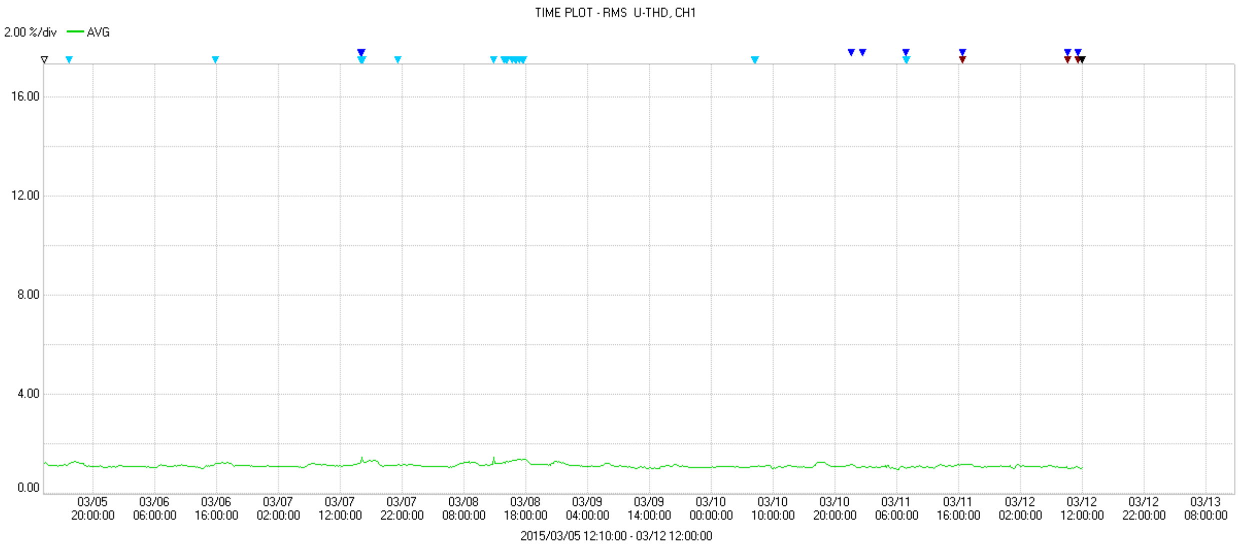
All the Uthds listed in the table constitute about 1%, which is smaller than the criteria. Moreover, the values in the brackets do not exceed 3%.

Accordingly, the harmonic voltage (low order) is not considered problematic in the Lae area distribution network.



Source: JICA Study Team

Fig. 2.8-12 Uthd at Milford S/S 11kV Bus in a Week (MIN, MAX, AVG)

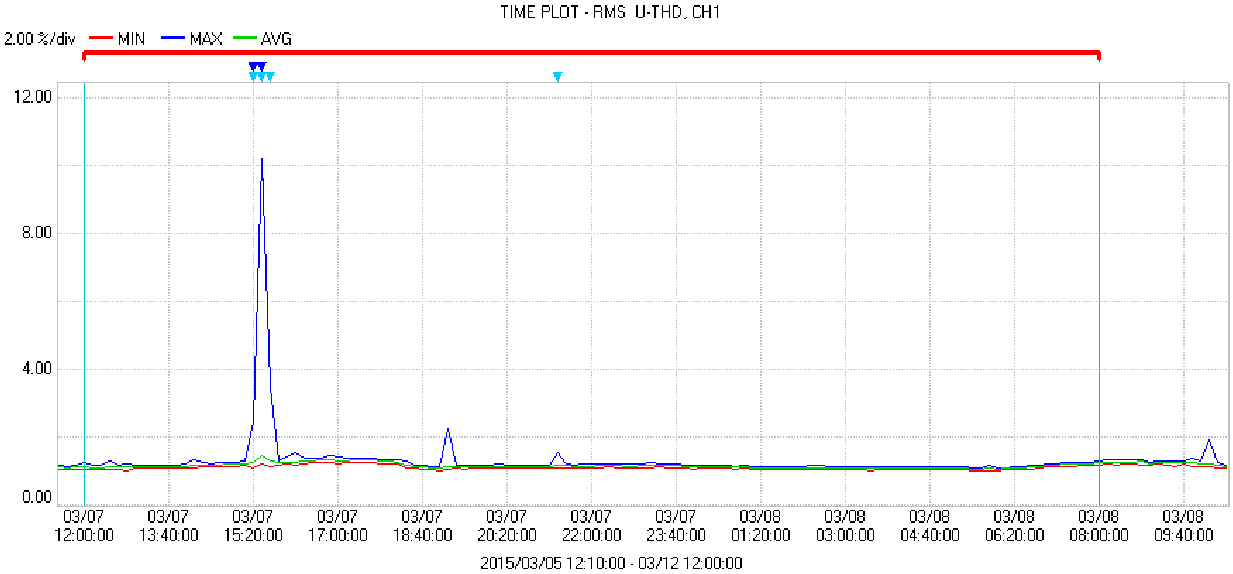


Source: JICA Study Team

Fig. 2.8-13 Uthd at Milford S/S 11kV Bus in a Week (AVG)

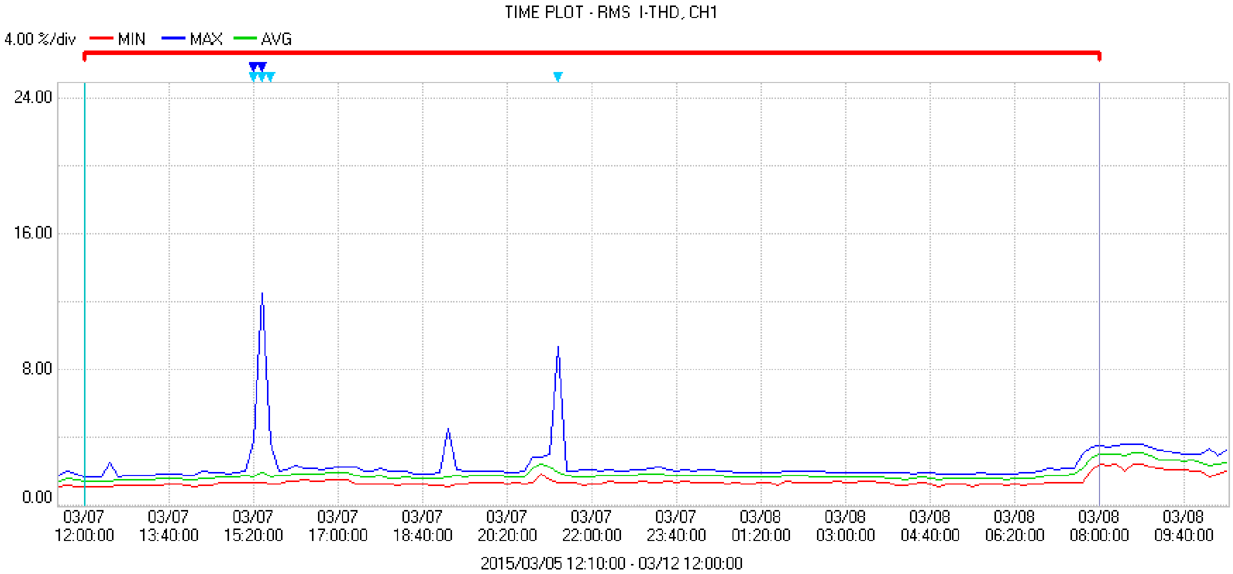
Fig. 2.8-12 shows all the values: the red is MIN, the blue is MAX and green is AVG. Conversely, Fig. 2.8-13 shows only the green (AVG). The short-term harmonics measured in the preliminary measurement was measured also in the long-term measurement. Consideration of the short-term harmonics is described below.

Fig. 2.8-14 shows Uthd at Milford S/S 11kV bus on 7 March. The MAX value exceeded 10% at 15:20 on 7 March. Moreover, the short-term harmonics occurred twice during 18:40~20:20 and 20:20~22:00. We call the short-term harmonics of the three A, B and C in order of time. Subsequently, Ithd at M1 on 7 March and at M2 on 7 March is shown in Fig. 2.8-15 and Fig. 2.8-16.



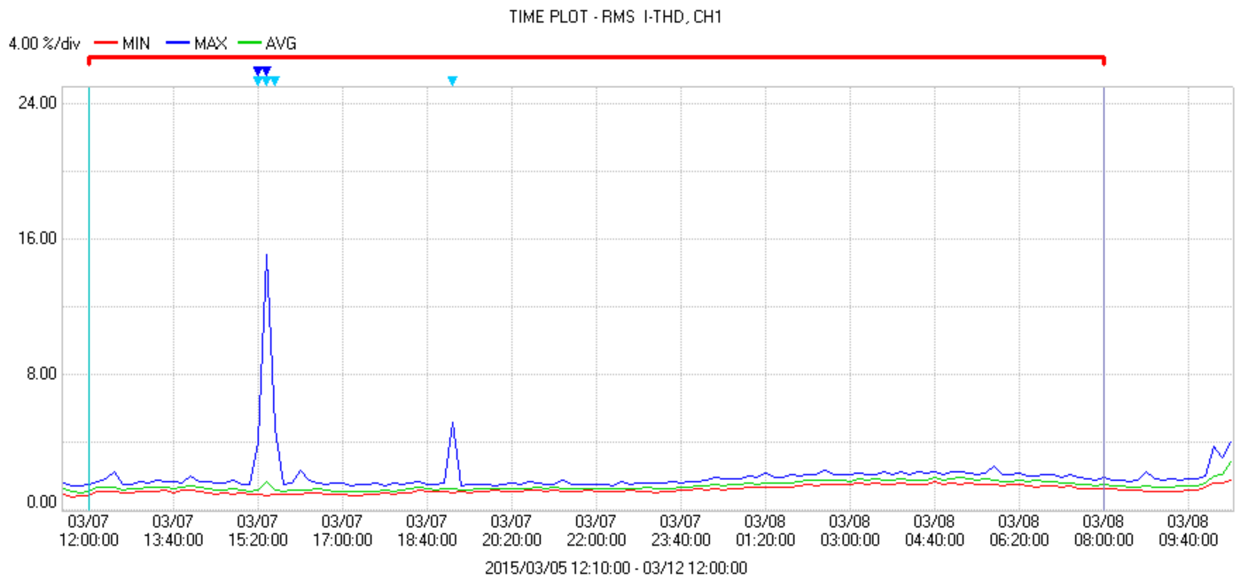
Source: JICA Study Team

Fig. 2.8-14 Uthd at Milford S/S 11kV Bus on 7 March



Source: JICA Study Team

Fig. 2.8-15 Ithd at M1 on 7 March



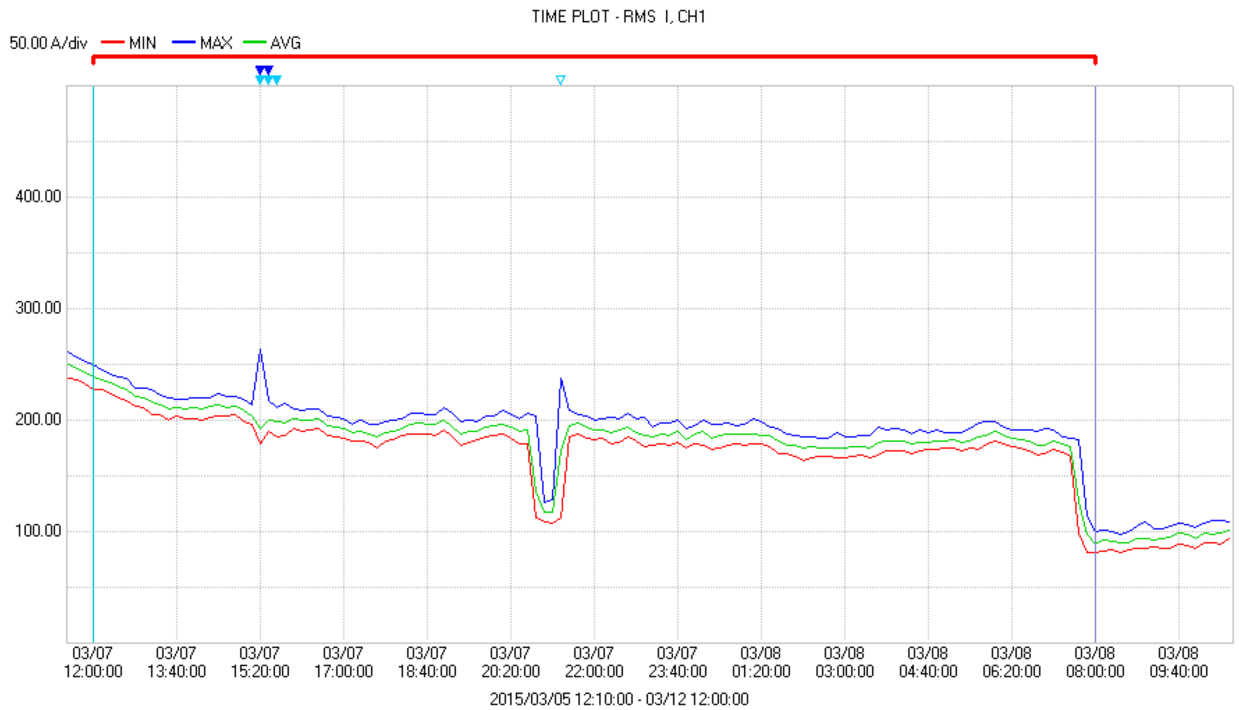
Source: JICA Study Team

Fig. 2.8-16 Ithd at M2 on 7 March

Compared with these two graphs, C is seen in Fig. 2.8-15 but not in Fig. 2.8-16. C is considered based on the harmonic current generated in the customer of M1 and comes from M1 to flow into the substation. If so, it can be considered that the distortion of the 11kV bus voltage in Fig. 2.8-14 was generated by the harmonic current flowing from M1 into the substation. Conversely, A and B are seen in all graphs in Fig. 2.8-14 to Fig. 2.8-16. These harmonics are considered generated in the system. It is said that the short-term harmonics were generated on both the system and customer sides.

Because these short-term harmonics exist for several hundred ms to several seconds, there is a high possibility that they are due to the distortion generated from the synchronization of generators on the system side and that at the start of equipment on the customer side. Fig. 2.8-17 shows the change in load current at the same time. This graph shows how the load current decreased from 190A to 120A at 21:00 (a fall of about 1.1MW) and then soared. Because the short-term harmonics occurred when the load soared, transient harmonics were considered generated by large equipment starting up on the customer side.

The typical adverse effects of harmonics include overheating of equipment such as capacitors and malfunction of equipment connected to the system. Because of the short period of short-term harmonics, no problem of overheating occurs. However, since the malfunction of the equipment happens stochastically, it is difficult to discuss quantitatively. Since such a malfunction of the equipment has not been confirmed, the short-term and intermittent harmonics are not considered to cause the equipment to malfunction.



Source: JICA Study Team

Fig. 2.8-17 I at M1 on 7 March

2) Harmonic voltage (high frequency)

We measured the harmonic voltage (high frequency) whose order is more than 50th. Table 2.8-5 shows the result. The high-order harmonic voltage component (UharmH) is an indicator of harmonic voltage (high frequency) which is expressed as RMS value. Fig. 2.8-18 shows the UharmH at Milford S/S 11kV bus in a week.

Table 2.8-5 High-order Harmonic Voltage Component (UharmH)

High-order harmonic voltage component (UharmH)		Milford S/S 11kV bus UharmH (V) brackets show the maximum value over one week			Taraka S/S 11kV bus UharmH (V) brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3	CH1	CH2	CH3
1 week	5-Mar	19 (30)	15 (26)	10 (21)	50 (65)	40 (53)	38 (58)
1 week	12-Mar	18 (32)	14 (25)	10 (22)	51 (68)	41 (55)	39 (56)
1 week	19-Mar	19 (51)	15 (37)	11 (33)	47 (60)	37 (51)	36 (55)
1 week	26-Mar	20 (56)	16 (46)	11 (42)	49 (63)	39 (53)	38 (57)

The UharmH is 10~20V in the Milford substation and 36~51V in the Taraka substation. The maximum value in the brackets is 68V, which is 0.6% of 11kV. As can be seen from Fig. 2.8-18, most of the measured values, except for those measured from the night of 9 March to the morning of 10 March, are considered errors caused by induction. Since these harmonic voltages (high frequency) do less harm on the equipment connected to the system, harmonic voltage (high frequency) is not considered problematic in the Lae area distribution network.

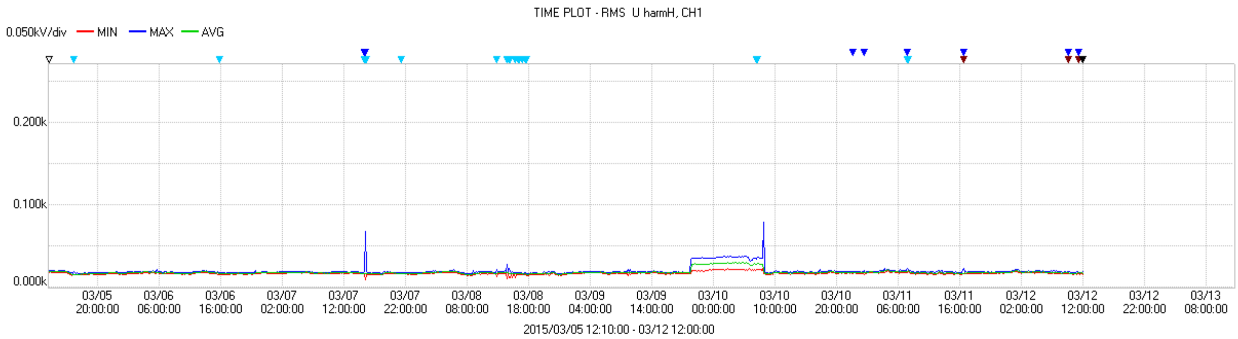


Fig. 2.8-18 UharmH at Milford S/S 11kV Bus in a week

Accordingly, harmonic voltage (low order to high frequency) is not considered problematic in the Lae area distribution network.

3) Harmonics current (low order)

We review the harmonics current compared to the criteria of 5% as described in the preliminary measurement.

Table 2.8-6 shows Ithd measured in the long-term measurement. Fig. 2.8-19 shows Ithd at M1 in a week.

Table 2.8-6 Total Harmonic Current Distortion Factor (Ithd)

Total harmonic current distortion factor (Ithd)		M1 Ithd (%) Brackets show the maximum value over one week			M2 Ithd (%) brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3	CH1	CH2	CH3
1 week	5-Mar-15	**1.98 (3.51)**	**2.29 (4.18)**	**2.18 (4.07)**	**1.53 (3.26)**	**1.63 (3.34)**	**1.47 (2.92)**
1 week	12-Mar-15	**2.00 (3.06)**	**2.44 (3.77)**	**2.44 (3.73)**	**1.54 (3.18)**	**1.61 (3.36)**	**1.42 (2.70)**
1 week	19-Mar-15	**1.36 (3.08)**	**1.48 (3.43)**	**1.45 (3.43)**	**1.65 (4.24)**	**1.70 (3.69)**	**1.58 (4.02)**
1 week	26-Mar-15	**1.65 (2.73)**	**1.96 (3.45)**	**1.79 (3.24)**	**1.73 (3.96)**	**1.87 (4.26)**	**1.60 (3.50)**

Total harmonic current distortion factor (Ithd)		T4 Ithd (%) brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3
1 week	5-Mar-15	**1.33 (2.04)**	**1.70 (2.66)**	**1.55 (2.29)**
1 week	12-Mar-15	**1.32 (3.46)**	**1.60 (3.45)**	**1.52 (3.99)**
1 week	19-Mar-15	**1.30 (2.71)**	**1.63 (2.97)**	**1.51 (2.98)**
1 week	26-Mar-15	**1.24 (2.40)**	**1.54 (2.69)**	**1.47 (2.71)**

Source: JICA Study Team

During the long-term measurement duration (24 hours × 28 days × 3 measuring points = 2016 hours), the 1919 hours' data is summarized in this Table except for 97 hours during outages. The brackets show the maximum value over one week as reference.

All the Ithds listed in the table constitute about 2%, which is smaller than the criteria. Moreover, the values in the brackets do not surpass 5%.

Accordingly, the harmonic current (low order) is not considered problem in the Lae area distribution network.

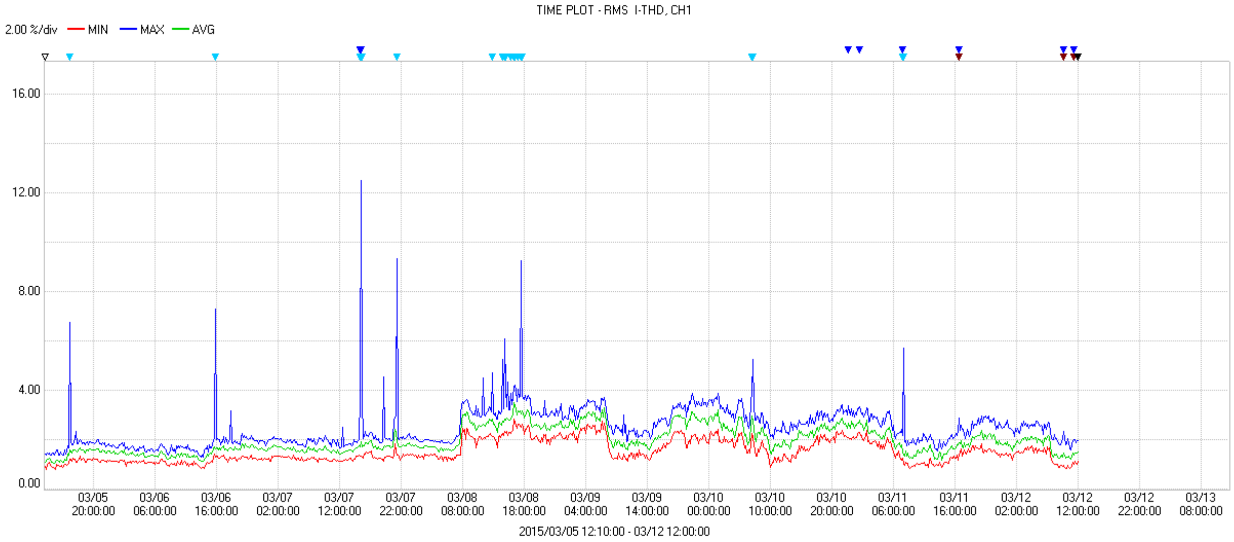


Fig. 2.8-19 Ithd at M1 in a Week

4) Harmonic current (high frequency)

We measured harmonic current (high frequency) whose order is more than 50th. High-order harmonic current component (IharmH) is an indicator of harmonic current (high frequency) which is expressed as RMS values. Table 2.8-7 shows the result. Fig. 2.8-20 shows the IharmH at M1 in a week.

Table 2.8-7 High-order Harmonic Current Component (IharmH)

High-order harmonic current component (IharmH)		M1 IharmH (A) Brackets show the maximum value over one week			M2 IharmH (A) Brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3	CH1	CH2	CH3
1 week	5-Mar-15	0.07 (0.13)	0.07 (0.14)	0.07 (0.12)	0.07 (0.18)	0.08 (0.19)	0.07 (0.18)
1 week	12-Mar-15	0.06 (0.13)	0.07 (0.74)	0.07 (0.74)	0.07 (0.17)	0.08 (0.19)	0.07 (0.18)
1 week	19-Mar-15	0.07 (0.14)	0.07 (0.16)	0.07 (0.15)	0.07 (0.18)	0.08 (0.19)	0.07 (0.18)
1 week	26-Mar-15	0.07 (0.27)	0.07 (0.19)	0.07 (0.25)	0.07 (0.22)	0.08 (0.18)	0.07 (0.22)

High-order harmonic current component (IharmH)		T4 IharmH (A) brackets show the maximum value over one week		
Duration	Start Day	CH1	CH2	CH3
1 week	5-Mar-15	0.8 (0.9)	0.8 (0.8)	0.8 (0.8)
1 week	12-Mar-15	0.8 (0.9)	0.8 (0.8)	0.8 (0.9)
1 week	19-Mar-15	0.8 (0.9)	0.8 (0.8)	0.8 (0.8)
1 week	26-Mar-15	0.8 (0.9)	0.8 (0.8)	0.8 (0.9)

Source: JICA Study Team

The IharmH is 0.06~0.08A in the Milford substation and 0.8A in the Taraka substation. The maximum value in the brackets is 0.9A, which is about 6% of the tentative current 100A.

As can be seen from Fig. 2.8-20, most of the measured values, except those measured from the night of 9 March to the morning of 10 March, are considered errors caused by the induction. Since these harmonic currents (high frequency) do less harm to the equipment connected to the system, harmonic current (high frequency) is not considered problematic in the Lae area distribution network.

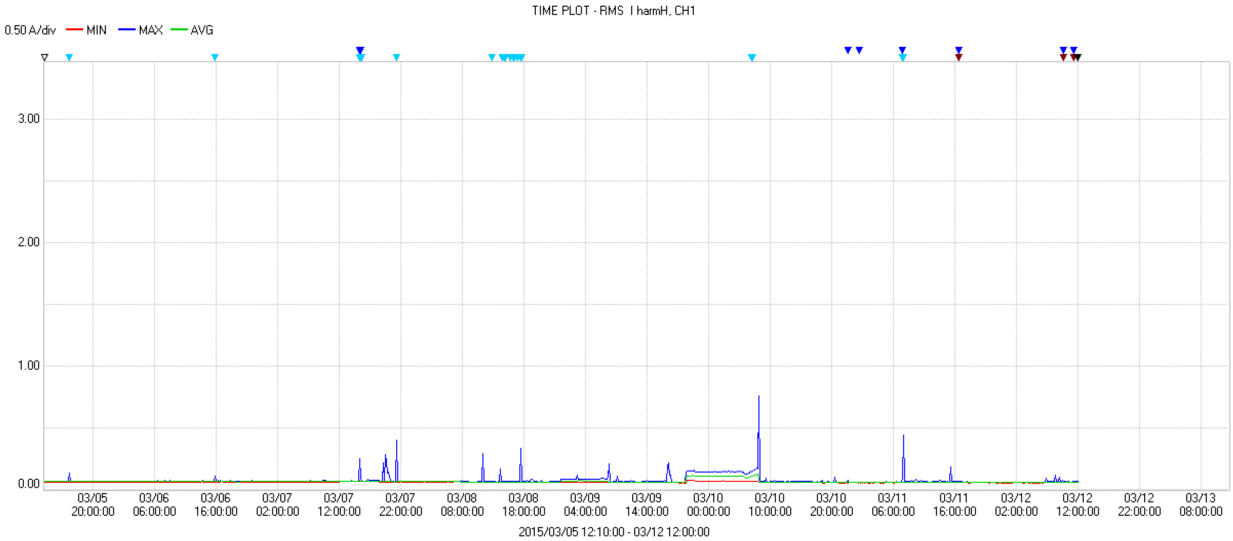


Fig. 2.8-20 IharmH at M1 in a week

Accordingly, harmonic currents (low order to high frequency) are not considered problematic in the Lae area distribution network.

5) Frequency

The regulation for the frequency is described in the PNG Grid Code. The part of the description is shown below.

- Frequency Variations and Limits

(i) The System Operator shall maintain the system frequency within the limits of 49.5 to 50.5 Hz during normal operation unless the Technical Regulator allows broader limits, based on technical studies on a specific grid.

(ii) During Single Outage Contingency, the system frequency may vary between 49 Hz and 51 Hz. In the case of Multiple Outage Contingency or when the Grid is in a state of emergency, the frequency may vary between 47 Hz and 52 Hz.

The description about the frequency in the Grid Code is summarized as follows:

49.5Hz~50.5Hz in the normal operation
49Hz~51Hz in the single outage contingency
47Hz~52Hz in the multiple outage contingency or a state of emergency

There is no description about the stay rate of the frequency.

We adopt EN 50160 which is the European standard to review the stay rate of the frequency.

EN 50160 is described as follows:

The nominal frequency of the supply voltage shall be 50 Hz. Under normal operating conditions the mean value of the fundamental frequency measured over 10 s shall be within a range of:

For systems with synchronous connection to an interconnected system:
50Hz±1% (49.5Hz~50.5Hz) during 99.5% of a year,
50Hz +4%/-6% (47Hz~52Hz) during 100% of the time

For systems with no synchronous connection to an interconnected system (e.g. supply systems on certain island):
50Hz±2% (49~51Hz) for 95% of a week
50Hz±15% (42.5Hz ~57.5Hz) for 100% of the time

In this report, we review the frequency compared to the criteria described in EN50160 as a reference.

This comparison is only a reference because the system capacity, measuring duration and so on differ.

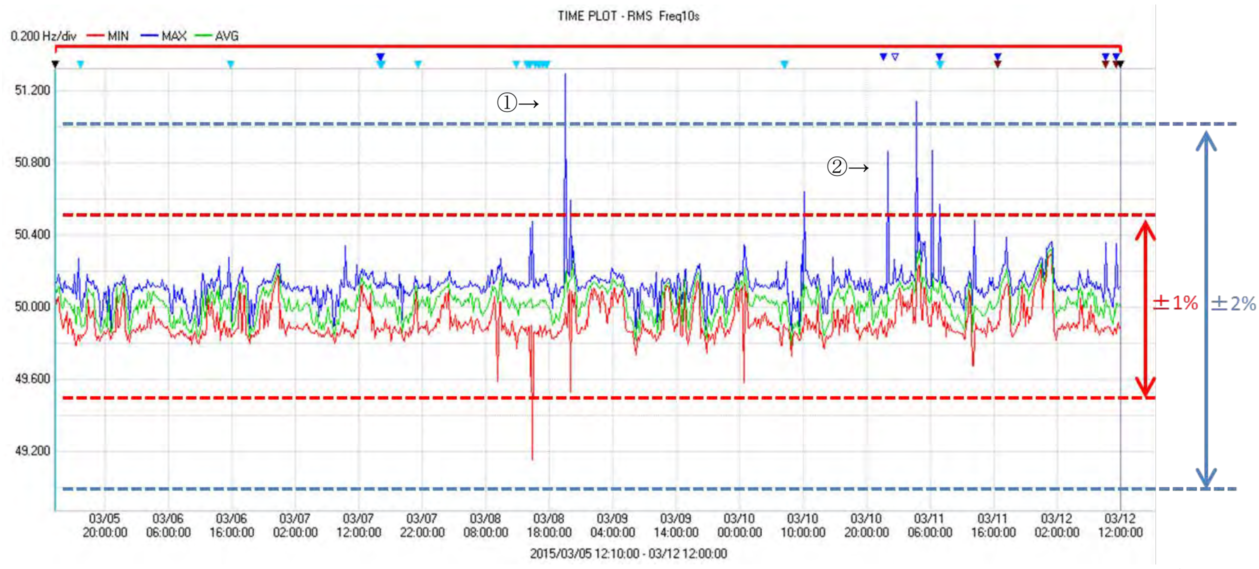
The number of frequency deviations is shown in Table 2.8-8. Fig. 2.8-21 shows the frequency fluctuation at Milford 11kV bus in a week as an example. It can be seen that the frequency deviated 7× over the upper limit and once under the lower limit.

According to the outage record of PPL, ① and ② in Fig. 2.8-21 are considered attributable to the sudden fall of a mine load and the trip of the 605 line (Gusap substation to Meiro substation) respectively. In this way, any rapid frequency fluctuation which deviates from the criteria is considered attributable to a system fault.

Table 2.8-8 Total Number of Frequency Deviations

		50Hz ±1%				50Hz ±2%			
Frequency Deviation (Times)		Milford S/S 11kV bus		Taraka S/S 11kV bus		Milford S/S 11kV bus		Taraka S/S 11kV bus	
Duration	Start Day	Over	Under	Over	Under	Over	Under	Over	Under
1 week	5-Mar-15	**7**	**1**	**7**	**1**	**2**	**0**	**2**	**0**
1 week	12-Mar-15	**13**	**6**	**13**	**4**	**3**	**1**	**6**	**1**
1 week	19-Mar-15	**74**	**29**	**41**	**17**	**23**	**8**	**13**	**7**
1 week	26-Mar-15	**23**	**8**	**22**	**7**	**7**	**1**	**5**	**2**

Source: JICA Study Team



Source: JICA Study Team

Fig. 2.8-21 Frequency Fluctuation at Milford 11kV Bus in a Week

Because Milford and Taraka substations are usually connected and synchronized to the Ramu system, the frequency in both fluctuates similarly. However, Milford and Taraka substations were isolated from the Ramu system from 21~23 March. Accordingly, the number of deviations increased during the week of 19 March and the number of deviations in the Milford substation differed from that in the Taraka substation.

The stay rate of frequency calculated from the result is shown as follows:

The case that the frequency during 10 minutes deviated both over and under the limit is counted once.

50Hz±1% (49.5Hz~50.5Hz) 97% (< 99.5%)
50Hz±2% (49Hz~51Hz) 99% (> 95%)

The frequency fluctuation doesn't meet 50Hz +/- 1% (99.5%), which is the criteria for systems with synchronous connection to an interconnected system.

However, the frequency fluctuation meets 50Hz +/- 2% (95%), which is the criteria for systems with no synchronous connection to an interconnected system (e.g. supply systems on certain islands).

Considering the capacity of the Ramu system, it can be said that frequency commensurate with its capacity has been implemented.

6) Voltage

When we review system voltage fluctuation, we generally separate the short- and long-term voltage fluctuation. The voltage fluctuation usually indicates the long-term voltage fluctuation and its criteria are usually regulated. For short-term voltage fluctuation, the transient voltage fluctuation such as swell and dip (or sag) exist in a system. Swell and dip are described later. In this section, the result of the long-term voltage fluctuation is shown.

The voltage fluctuation is limited to within +/-5% in FYPDP (2014-2028) which is the 15-year plan of PPL. However, there is no description of the voltage stay rate.

We adopt EN 50160, which is the European standard, to review the voltage stay rate.

EN 50160 is described as follows:

At least 99% of the 10 min mean r.m.s values of the supply voltage shall be below the upper limits of + 10%

At least 99% of the 10 min mean r.m.s values of the supply voltage shall be above the lower limits of - 10%

In this report, we review the voltage compared to the criteria described in EN50160 only for the voltage stay rate as a reference.

This comparison is only a reference because the value of the criteria differ.

Table 2.8-9 shows the number of voltage deviations during long-term measurement. It can be seen that the voltage deviated once over the upper limit and 2× under the lower limit.

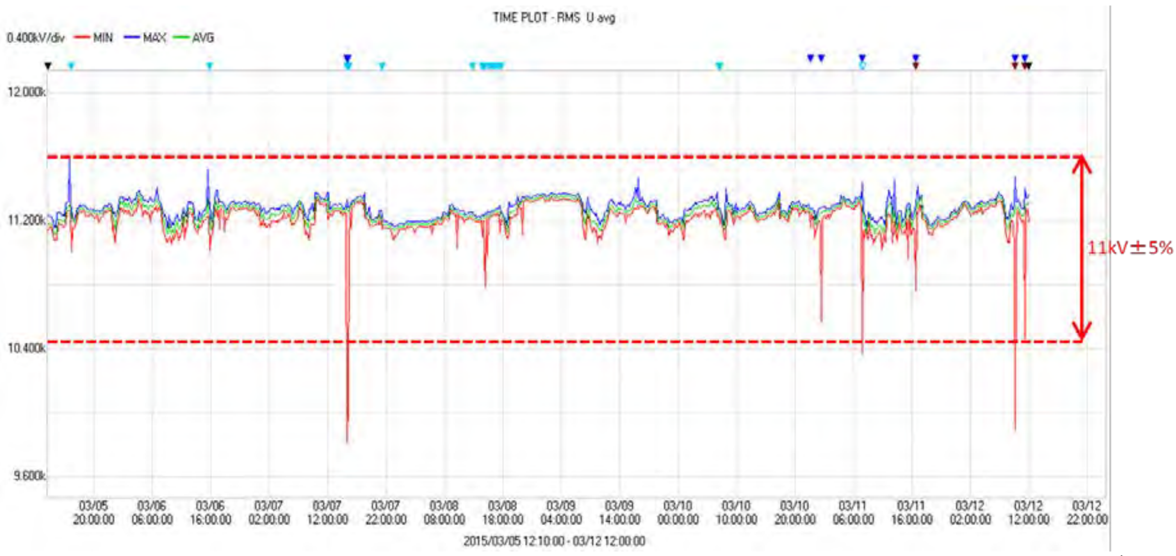
Fig.2.8-22 shows the voltage fluctuation at Milford 11kV bus in a week.

Table 2.8-9 Total Number of Voltage Deviations

Vrms (V)		Milford S/S 11kV bus Voltage (V)		Taraka S/S 11kV bus Voltage (V)	
Duration	Start Day	Over	Under	Over	Under
1 week	5-Mar	0	0	0	0
1 week	12-Mar	0	0	0	0
1 week	19-Mar	1	2	0	0
1 week	26-Mar	0	0	0	0

Source: JICA Study Team

This table shows the voltage stay rate is 99.9% and most of the values measured during the long-term measurement are within the criteria (+/-5%). The load tap changer in the substation of Lae city is set on 11.2kV+/-1%. The voltage at 11kV bus in the substation is controlled as it was set in advance.

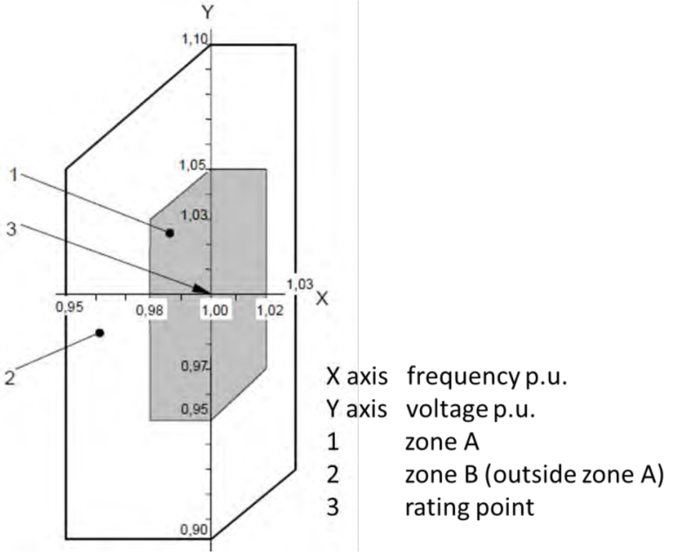


Source: JICA Study Team

Fig.2.8-22 Voltage Fluctuation at Milford 11kV Bus in a Week

The graph shows how the AVG voltage is limited to within 11kV +/-5% (10.45kV~11.55kV) in the center of 11.2kV.

Subsequently, we explain the extent to which this voltage and frequency fluctuation affect customers' equipment with an example.



Source: IEC 60034

Fig. 2.8-23 Voltage and Frequency Limits for Motors

Fig. 2.8-23 shows the voltage and frequency limits for motors.

According to the IEC standard, zones A and B are described as follows:

A machine shall be capable of performing its primary function within zone A, but need not comply fully with its performance at rated voltage and frequency and may exhibit some deviations.
Temperature rises may be higher than at rated voltage and frequency.
A machine shall be capable of performing its primary function within zone B, but may exhibit greater deviations from its performance at rated voltage and frequency than in zone A.
Temperature rises may be higher than at rated voltage and frequency and most likely will be higher than those in zone A. Extended operation at the perimeter of zone B is not recommended.

The voltage and frequency in the system remain in zone A at the rate of 99% and temporarily in zone B. It is considered that the voltage and frequency during normal operation hardly affect the operation of the motors connected to the system.

7) Swell, Dip

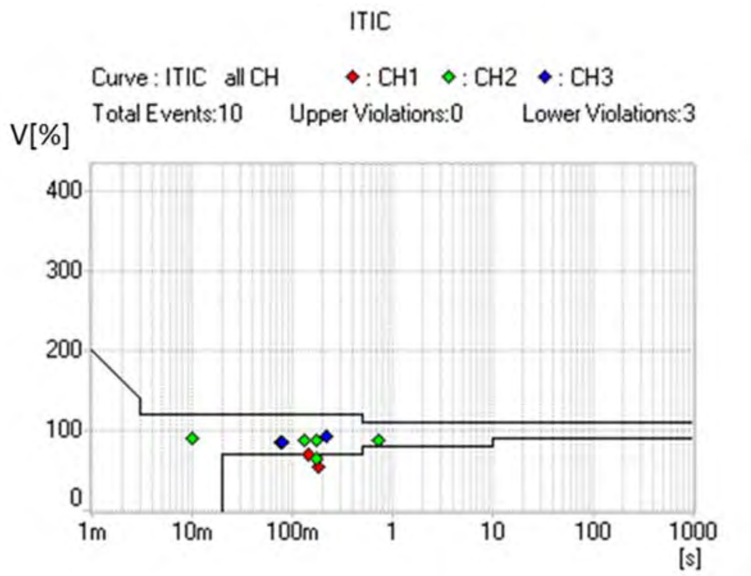
Swell and dip mean short-term voltage fluctuations. This fluctuation may cause adverse effects such as interrupting the power supply to customers' equipment.

The short-term voltage increase is called swell and short-term voltage decrease is called dip. These short-term voltage fluctuations are due to faults in the T/L and switching of heavy loads. Above all, it is mainly caused by lightning faults of the T/L. The voltage drops from the occurrence of the fault until separation by the circuit breaker. It is difficult to prevent all faults in the T/L and also to eliminate the time from occurrence to separation. This means that it is difficult to prevent the system from causing the short-term voltage fluctuation. It is considered reasonable to have countermeasures for short-term voltage fluctuation implemented by the customer.

One of the ways to review the voltage fluctuation such as swells and dips is the Information Technology Industry Council (ITIC) Curve. This is a graph created by the ITIC plotting voltage disturbance data for detected events using the event duration and worst value (as a percentage of the nominal input voltage).

The graph format makes it easy to swiftly identify which event data distribution should be analyzed.

Fig. 2.8-24 shows an example of the ITIC Curve. The graph is plotted based on the swells and dips having occurred at Milford S/S 11kV bus in a week. The events plotted over or under the black line mean the deviation of the voltage fluctuation criteria. In other words, the deviation events may cause adverse effects such as the interrupting the power supply to customers' equipment. The graph shows that the dips occurred ten times and three of the ten incidents saw the lower limit surpassed during the week.



Source: JICA Study Team

Fig. 2.8-24 Comparison between ITIC and Short-Term Voltage Fluctuation at Milford S/S 11kV Bus in a week

Table 2.8-10 shows the number of swells and dips during the long-term measurement.

Table 2.8-10 Total Number of Swells and Dips

Swell and Dip		Milford S/S 11kV bus				Taraka S/S 11kV bus			
		Dip		Swell		Dip		Swell	
Duration	Start Day	total	deviation	total	deviation	total	deviation	total	deviation
1 week	5-Mar	10	3	0	0	8	2	0	0
1 week	12-Mar	4	1	0	0	0	0	0	0
1 week	19-Mar	40	15	0	0	26	9	0	0
1 week	26-Mar	19	2	2	0	6	1	0	0

Source: JICA Study Team

Swells occurred only twice. Most of the short-term voltage fluctuation occurring in the Ramu system turned out to be dips. This is considered attributable to the minimal rise in voltage in the sound phase during faults due to the direct grounding system. The number of dips increased in the week of 19 March.

For the short-term voltage fluctuation in the Ramu system, mainly dips occurred, some of which deviated from the ITIC Curve several times a week. It is desirable that measures against such dips, such as UPS, should be implemented in the equipment which is difficult to restart soon.

8) Outage

Continuity of power supply is one of the key factors determining the quality of electricity. However, the outage record is collected by PPL and its analysis is described in this report. In this section, only the time of the outage which occurred during the long-term measurement is shown in Fig. 2.8-25 and Fig. 2.8-26. M1, M2 and T4 are the feeders on which measuring instruments were installed during long-term measurement.

	5-Mar	6-Mar	7-Mar	8-Mar	9-Mar	10-Mar	11-Mar	12-Mar	13-Mar	14-Mar	15-Mar	16-Mar	17-Mar	18-Mar
M1										06:49-14:28				
M2														
M3														
M4	15:42-16:02	15:20-15:45										14:35-14:42	16:35-17:11	
M5							07:28-07:38							
M6	10:44-11:47		10:00-19:02	08:50-11:16 17:17-17:25						10:31-10:46 10:46-18:46	10:10-10:12 10:12-18:20			
T1														
T2														
T3								09:21-09:28 09:42-11:21		08:15-12:44				
T4			09:44-16:06					11:15-11:20	15:32-16:32					
T5								09:34-09:36						

Source: JICA Study Team

Fig. 2.8-25 Distribution Outages from 5-18 March

	19-Mar	20-Mar	21-Mar	22-Mar	23-Mar	24-Mar	25-Mar	26-Mar	27-Mar	28-Mar	29-Mar	30-Mar	31-Mar	1-Apr	2-Apr
M1			00:03-01:21		09:30-10:31 13:20-13:49 17:13-17:56 18:07-18:21								03:43-04:42 06:01-06:22		
M2		22:12-23:55	00:03-00:55		09:30-10:29 17:23-17:24 17:29-17:48			11:52-11:53					03:43-04:39 06:01-06:20		20:49-21:14
M3			00:03-02:42		09:30-10:27 17:29-17:49 18:10-18:23								03:43-04:41 06:01-06:22		
M4			00:03-02:43		09:30-10:27 17:14-17:27 17:29-17:54 18:10-18:23								03:43-04:40 06:01-06:21		20:49-21:22
M5			00:03-02:04		09:30-10:30 17:16-17:26 17:29-17:50 18:10-18:24			11:52-11:53					03:43-04:39 06:01-06:20		20:49-21:14
M6		05:15-05:22 09:43-12:17	00:03-02:43 08:56-08:58 08:58-16:22	02:46-07:27 08:58-09:02 09:02-17:45	09:30-10:27 17:17-17:27 17:29-17:51 18:10-18:25	09:17-09:26		11:52-11:54		09:23-19:35			03:43-04:41 06:01-06:21	11:05-11:15	19:40-20:06 20:49-21:15
T1			00:03-02:23	16:12-17:06				11:45-11:48							20:49-21:23
T2			00:03-02:38	16:11-17:01		09:10-09:22	15:29-15:30	11:45-11:50							20:49-21:20
T3	17:03-19:18	22:15-00:00	00:00-02:38 03:02-10:36	16:10-21:00						10:28-10:49					
T4			00:03-02:37	16:09-16:57		09:07-09:22			02:07-08:01	00:20-00:56					
T5			00:03-02:37	00:57-09:48 16:08-16:54				11:45-11:47							20:49-21:10

Source: JICA Study Team

Fig. 2.8-26 Distribution Outages from 19 March to 2 April

(3) Summary

To determine the effect of the harmonics (low order to high frequency) and power quality in Lae city, we measured the 11kV distribution network for 4 weeks in the substation. The result of the long-term measurement is summarized below.

- Harmonics are not considered problematic.
- In the Ramu system, it can be said that frequency control commensurate with its capacity has been implemented. The rapid frequency fluctuation which deviates from the criteria is due to the fault of the system.
- The voltage at 11kV bus in the substation is controlled within the limits of normal operation.
- Most of the short-term voltage fluctuation occurring in the Ramu system turns out to be dips. It is desirable that countermeasures for such dips should be implemented by the customer if necessary.

2.9 ONGOING AND UNDER CONSTRUCTION PROJECT OF NETWORK SYSTEMS IN THE LAE AREA

2.9.1 Ramu Transmission System Reinforcement Project

The main objective of this project is to reinforce the existing 132kV T/L between the Ramu 1 hydro P/S and Taraka substation in Lae city, Morobe Province to enhance the power supply reliability and stability of the Ramu grid by:

1. Reinforcing the efficiency of the Ramu grid, which is considered to lead directly toward the stabilization of electric power supply and economic development, and

2. Increasing opportunities for reliable and stable electrical connections in neighboring communities to the project sites

Specification of the Project

1) Transmission line components

i) 132kV double-circuit overhead T/L from Taraka substation to Taraka junction, 0.7 km and 132kV single-circuit overhead T/L from Taraka Junction to Erap substation, 39.7 km

ii) 132kV double-circuit overhead T/L between Erap substation and new Singsing substation, 97.2 km

2) Substation components

i) Rehabilitation of the Ramu 1 switchyard

ii) Construction of Singsing substation, including one unit of 132/33kV 10 MVA main power transformer and six 132kV T/L bays

iii) Augmentation of Erap substation, including additional two units of 132/66/33kV 10 MVA main power transformers and three T/L bays

iv) Rehabilitation of the Taraka substation with the following three alternative plans, including additional one 132kV T/L bay

Plan A: Rehabilitation of 132kV switchgear with full AIS

Plan B: Only 132kV T/L feeders are to be Gas Insulated Switchgear (GIS) and other parts such as 132kV bus bar and main transformer bays are to be AIS

Plan C: Rehabilitation of 132kV switchgear with full GIS

Fig. 2.9-1 Ramu Transmission System Reinforcement Project Route

Source: FIFTEEN-YEAR POWER DEVELOPMENT PLAN, PPL

Table 2.9-1 Cost of Ramu Transmission System Reinforcement Project

Items	FC (US$)	LC (US$)	Total (US$)	Total (PGK eq.)	Total (JPY eq.)
1. Transmission Line Component	17,033,600.00	17,611,400.00	34,645,000.00	79,433,300.00	2,805,898,000
2. Substation Component					
2.1 Plan A	16,700,600.00	8,678,300.00	25,378,900.00	58,188,500.00	2,055,437,000
2.2 Plan B	18,683,900.00	9,020,200.00	27,704,100.00	63,519,600.00	2,243,755,000
2.3 Plan C	21,010,200.00	9,185,700.00	30,195,900.00	69,232,700.00	2,445,566,000
3. Land & ROW Compensation	-	931,320.00	931,320.00	2,135,400.00	75,427,000
4. Consulting Fee	3,233,400.00	1,788,400.00	5,021,800.00	11,513,900.00	406,715,000
5. Contingency (8% of 1+2)					
5.1 Contingency Plan A	2,698,700.00	2,103,200.00	4,801,900.00	11,009,700.00	388,906,000
5.2 Contingency Plan B	2,857,400.00	2,130,500.00	4,987,900.00	11,436,200.00	403,970,000
5.3 Contingency Plan C	3,043,500.00	2,143,800.00	5,187,300.00	11,893,400.00	420,119,000
Grand Total (Plan A)	39,666,300.00	31,112,620.00	70,778,920.00	162,280,800.00	5,732,383,000
Grand Total (Plan B)	41,808,300.00	31,481,820.00	73,290,120.00	168,038,400.00	5,935,765,000
Grand Total (Plan C)	44,320,700.00	31,660,620.00	75,981,320.00	174,208,700.00	6,153,725,000

Source: 2nd Preparatory Survey on The Project for Reinforcement of Ramu Transmission System in the Independent State of Papua New Guinea FINAL REPORT, JICA

2.9.2 Milford Substation 11kV Indoor Switchgears Replacement Project

(1) Background

Our Transmission System comprises POM, Ramu and Gazelle Network Grids. Most of the switchgears on these systems are old and often malfunction, affecting the reliability of the electricity service to our valued customers and need replacing immediately.

(2) Project objectives

To identify, purchase, replace/install and commission various Transmission Switchgear within our transmission grids to improve system protection, reliability and switching flexibility.

(3) Desired outcomes

To minimize unnecessary power outages due to switchgear failure in the system and improve protection reliability and equipment security.

(4) Project scope and exclusions

- Tender and procurement
- Installation schedule and planning
- Site construction
- Testing and commissioning

(5) Site location

Fig. 2.9-2 Site of Milford Substation 11kV Indoor Switchgears Replacement Project

Source: JICA Study Team

(6) Budget

3.9 Million Kina

Table 2.9-2 Cost of Milford Substation 11kV Indoor Switchgears Replacement Project

Item	Cost (Kina)
Procurement	2,662,500.00
Construction	75,000.00
Estimated man-hours	115,000.00
Labor & ongoing costs	75,700.00
Contingencies	439,230.00
Overheads 5%	146,410.00
GST	217,350.00
Budget Total	3,865,224.00

Source: Project Brief, Version 01_00, PPL

2.9.3 Other Planned Projects

(1) Fifteen-Year Power Development Plan

In the FYPDP, the following projects are listed. Refer to Table 2.9-3.

Table 2.9-3 List of Transmission Development Plans in Lae

Year	Works
2018	Commence Ramu 2 to Singsing 132kV transmission line
2022	Transmission line interconnection to Lae Independent Power Producer (IPP) 2 Power Plant
2027	Complete the Ramu 2 to Singsing 132kV transmission line Review the Interconnection to the Port Moresby system – this development depends on the availability of major generation capacity in Ramu or Port Moresby.

Source: FIFTEEN-YEAR POWER DEVELOPMENT PLAN, PPL

(2) PPL Operating & Maintenance Department

In the PPL Operating & Maintenance Department, the following projects are listed. Refer to Table 2.9-4.

Table 2.9-4 Cost and Specification of New Projects in Lae by the O&M Department

Issue/Activity	Specification	Cost estimate (kina)	Status	Location of project
Transmission/ Ramu Substation	Milford sub 11kV upgrade	K1.5m	BP circulating for signatures.	Milford (S/S) A
	Milford sub 66kV outdoor switchgear upgrade	K2.75m	Design and specification stage	Milford (S/S) A
	Taraka sub additional 2off 11kV indoor switchgear	K200,000	Set for 31/06/15 Switchgears on site	Taraka (S/S) B
	Taraka sub 132/66kV auto-Tx 3 CB	K300,000	Set for 31/06/15. 50% complete	Taraka (S/S) B
	Taraka sub 132/66kV Tx 4 CB	K300,000	Set for 31/06/15. Awaiting control cables on order	Taraka (S/S) B
	Oil circulation & maintenance Milford Sub Tx 2	K10,000	Set for 31/12/14	Milford (S/S) A
	Oil circulation & maintenance Milford sub Tx 1	K10,000	Set for 31/01/15	Milford (S/S) A
	Taraka 509 line VT replacement	K250,000	Set for 31/01/15	Taraka (S/S) B
Distribution/ Lae Distribution	Installation of 700 kVA Tx Kiosk with inter poling-Raumai 18 Supermarket	K317,080	Set for 28/02/15. Design & quote delivered. Awaiting payment under CAA	In Lae City
	Installation of 1000 kVA Tx Kiosk-Raumai 18 sec 8 lot 11	K248,298	Set for 28/02/15. Design & quote delivered. Awaiting payment under CAA	In Lae City
	Installation of 500 kVA Tx Kiosk type for Highlands Products (Zenag Egg) sec 16 lot 1	K176,946	Set for 28/02/15. Design & quote delivered. Awaiting payment under CAA	In Lae City
	Lings Freezer 300 kVA Tx type	K148,621	Set for 28/02/15. Design & quote delivered. Awaiting payment under CAA	In Lae City
	Frabelle PNG 3 MVA Kiosk at Spybank St	-	Set for 28/02/15. Sketch & specs submitted for quote	In Lae City
	Raumai 18 300 KVA Kiosk at Malaita St	-	Set for 28/02/15. Sketch & specs submitted for quote	In Lae City

Source: O&M Monthly Team Summary (December 2014), PPL

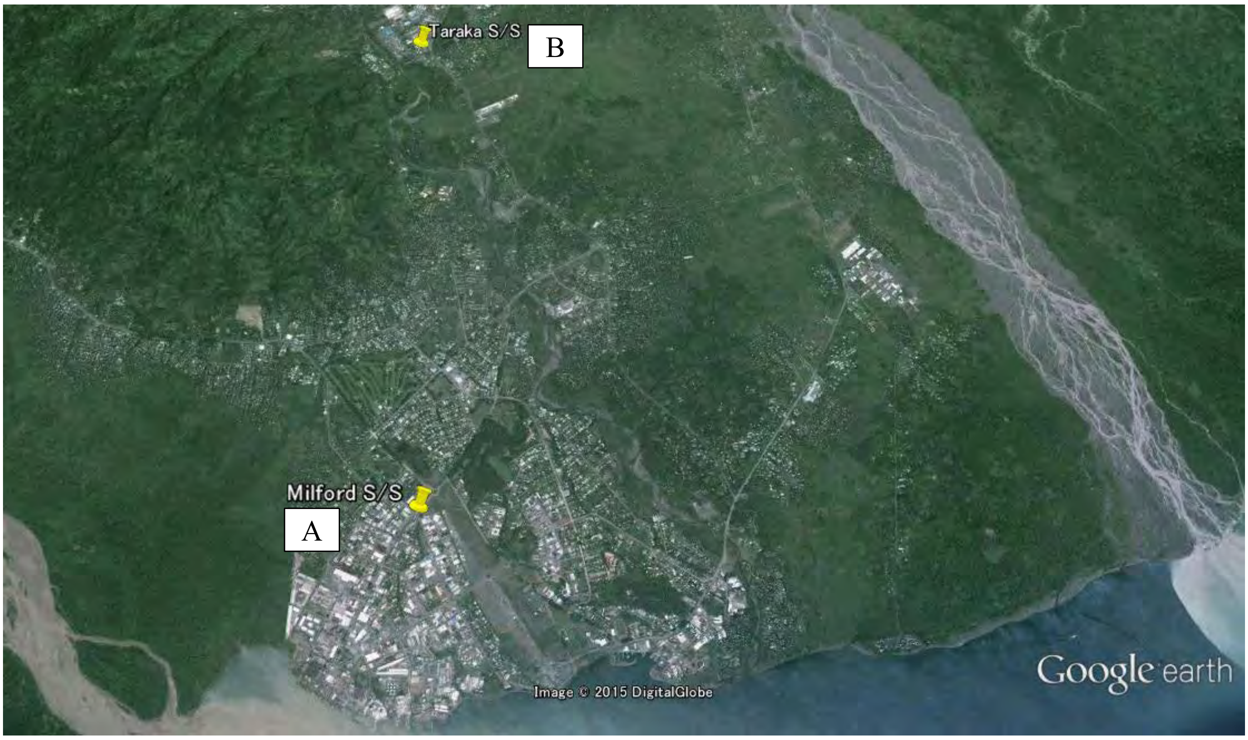


Fig. 2.9-3 Sites of New Projects by O&M Department

Source: JICA Study Team

2.10 CLARIFICATION ON ISSUES ON THE NETWORK SYSTEM IN LAE

2.10.1 Clarification on Issuers within the Distribution Network in LAE

The key issues at the Lae distribution network are as follows:

Table 2.10-1 Clarification on Issuers within the Distribution Network

No.	Category	Item	Remarks
1	Defect of facilities	Switching restrictions	Refer to Section 2.3.5 Distribution Switchgears
2	Defect of facilities	Conductor capacity constraints	Refer to Section 2.3.2 Conductor
3	Defect of facilities	Replacement/ upgrading of 11kV facilities in Milford Substation	Refer to Section 2.3.8 Protection Relay
4	Human factor	Management method of Load	Refer to Section 2.4 Operation and Maintenance of Power Systems in the Lae area
5	Others	Management method of drawings.	

2.10.2 Implementation for the Issuers

Based on a policy and plan to improve the short-term distribution network based on outage record analysis, JICA Study Team focuses on reducing the outage duration rather than frequency to improve supply reliability in the short-term distribution network improvement plan.

From the perspectives of urgency and importance, the following countermeasures are selected for the short-term distribution network improvement plan, prioritizing the urban area.

For the long-term distribution network improvement plan, the equipment/network reinforcement study will be conducted based on the result of the demand forecast. The target area is the Lae area, including Nadzab S/S, Erap S/W.

About the technical guidance, JICA Study Team continue the field survey about Operation and Maintenance and discuss with PPL and JICA PNG, whereupon the implementation item will be decided.

Table 2.10-2 Contents of in Short-Term Distribution Network Improvement Plan

No.	Contents	SR	SC
1	Upgrading ABS to Load-Break Switch (LBS) on existing 11kV lines in Lae city to avoid switching restrictions	#	
2	Reconfiguration of the 11kV Distribution Network (Power Supply Area)	#	
3	Replacement of small-sized conductors of 11kV D/Ls with the standard conductors to remove constraints on network utilization	#	
4	Replacement/ upgrading of 11kV facilities such as 11kV electric cable, current transformer, circuit breaker in Milford Substation to remove restrictions on feeder capacity	#	#

SR: to improve supply reliability
SC: to improve supply capacity

CHAPTER 3

BASIC DESIGN OF THE DISTRIBUTION NETWORK STRUCTURE

CHAPTER 3 BASIC DESIGN OF THE DISTRIBUTION NETWORK STRUCTURE

3.1 MASTER PLAN FOR THE RAMU POWER SYSTEM

3.1.1 Demand Forecast of the Lae Area

To settle the facility plan, such as the substation and D/L, a demand forecast for each region in the Ramu system is important. Here, the demand forecast of each Center where each service center is located, is implemented until 2030. The following analytical steps are performed:

- Each Center's growth rate is estimated from historical data
- Each Center's peak demand is estimated from historical data
- Each Center's peak demand is divided to each existing substation where the summation of each Center's peak demand conforms to the peak demand of Base Load in Normal Case
- For substations in Lae and Madang Center, new industrial/commercial estate loads are added

Base Load's peak demand of each Center estimation result until 2030 are shown in Fig. 3.1-1, Base Load's peak demand ratio of each center in 2030 is shown in Fig. 3.1-2 and each substation's peak demand estimation result is shown in Fig. 3.1-3.

On the Base Load as of 2030, the peak demand of Lae Center is the biggest, followed by Madang Center. In the forecast, the peak demand of Lae Center is 50% of the total Base Load and Madang is 18%.

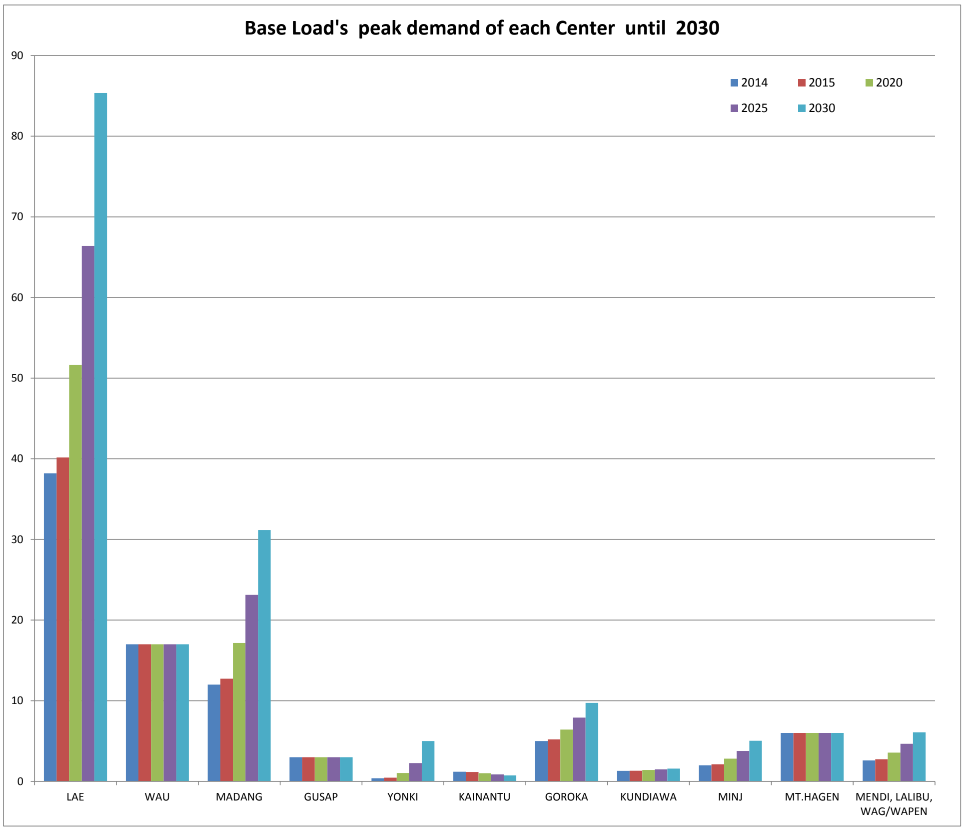


Fig. 3.1-1 Base Load's Peak Demand of Each Center until 2030

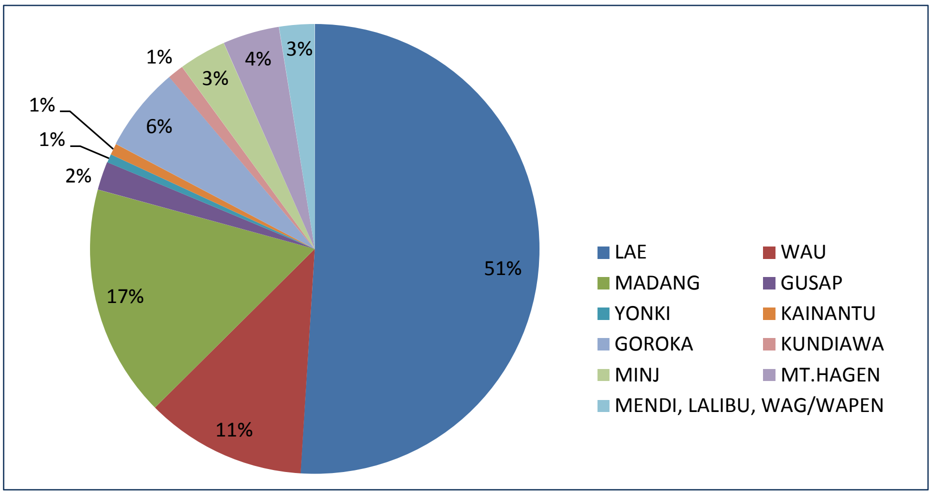


Fig. 3.1-2 Base Load's Peak Demand Ratio of Each Center in 2030

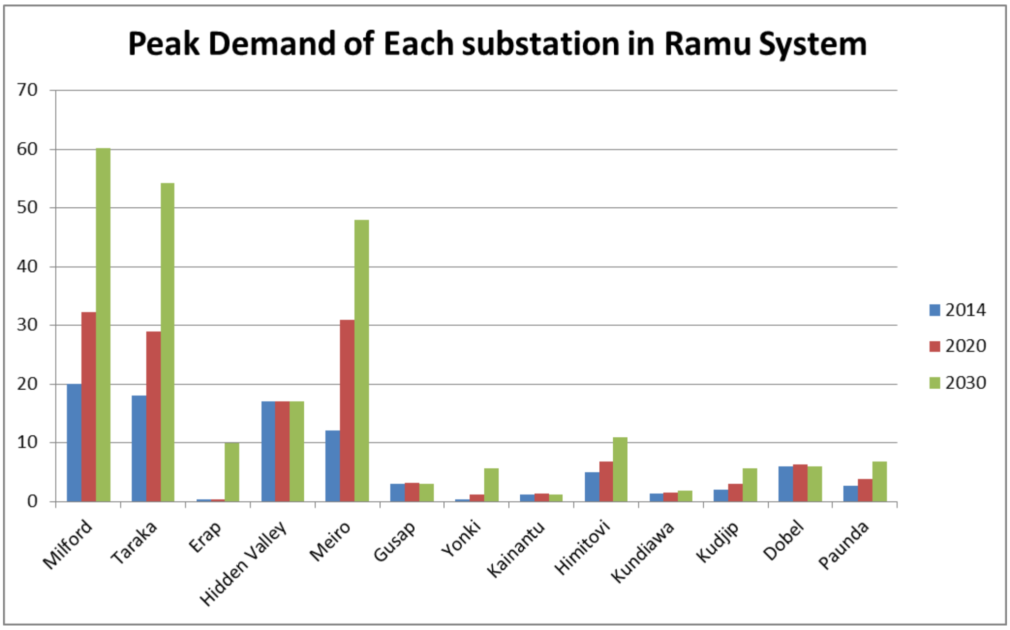


Fig. 3.1-3 Peak Demand of Each Substation until 2030

3.2 BASIC DESIGN OF THE DISTRIBUTION NETWORK STRUCTURE

In this section, the structure of the distribution network is defined in accordance with the actual conditions of the Lae Area from the perspective of ensuring supply reliability, reducing power losses and ensuring ease of operation and maintenance.

Power distribution planning and design significantly impact on the following factors, which affect service quality to customers and business management.

✓ Construction cost of facilities
✓ Power supply quality (Supply voltage and reliability)
✓ Power losses

Considering them overall, distribution planning is required, taking all these factors into consideration, to form well-balanced facilities since those factors tend to interact.

The distribution network structure design defines the main facility planning issues to ensure conformance with the planned distribution facilities, standard form of facilities and standards for scale and capacity etc. to achieve an efficient and harmonious delivery system, including distribution substations (primary substation) and a high voltage line taking overall factors affecting service quality to customers and business management into consideration.

The basic design for the distribution network structure should be based on PPL standards such as Grid code and Design manual as far as possible.

3.2.1 Basics in Distribution Network Structure Design

(1) Policy and evaluation of facilities formation

The following matters should be considered in distribution design to ensure stable long-term supply and overall system efficiency.

a. Effective utilization of existing facilities
b. The economy taking into account the construction costs and distribution losses in capital
c. Flexibility for future demand fluctuations
d. Harmony with the local community
e. Maintaining and improving power quality and supply reliability
f. Coordination of facilities and O&M
g. Ease of construction and installation

(2) Judgment of the need for countermeasure and the required timing

Assuming maximum utilization of existing facilities, planning for new installation and expansion should be developed based on the following conditions:

a. When substation facilities or equipment is newly installed
b. When the capacity of existing facilities is expected to become insufficient
c. When existing facilities is expected to be unable to maintain permissible voltage levels
d. When extensive or extended power outages are expected during a single equipment failure (N-1 fault) in existing facilities
e. When upgrading capacity or specification is considered profitable due to increasing maintenance cost and power losses in existing facilities

f. When some renovation of facilities is deemed necessary to address power outages caused by work on D/Ls and frequent faults

3.2.2 Prerequisites of Facility Planning

(1) Nominal voltage and Circuit type of the distribution system

Nominal voltage and circuit type distribution systems are shown in Table 3.2-1 as standard.

Table 3.2-1 Nominal Voltage and Circuit Type

Voltage class	Application area	Nominal voltage	Circuit type
11kV System	In the city of Lae (Taraka S/S, Milford S/S Area)	11kV	3-phase 3-wire system with solid earthing
22kV System	Rural area other than the above (Elap S/S, Nadzab S/S Area)	22kV	3-phase 3-wire system with solid earthing
Low voltage System	Whole area	415/240V	3-phase 4 wire system with solid earthing

(2) Maintaining proper voltage

Facilities should be established to maintain supply voltage for low voltage customers within the permissible range shown in Table 3.2-2.

Table 3.2-2 Permissible Voltage

Nominal voltage (V)	Permissible voltage (V)
415	415±5%
240	240±5%

(3) Type of distribution line

D/Ls should be overhead lines in principle. However, underground cables should be adopted under the following conditions. JICA Study Team consider the adoption of underground lines in the following cases:

a. Parts leading out feeders from substations
b. Where regulatory and technological constraints apply, which limit the construction of overhead lines, or based on the on-site situation and economic conditions
c. When an underground cable is required to harmonize with the local environment

(4) Standard distribution circuit capacity

The form of leading out and standard circuit capacity are shown in Table 3.2-3.
A facility expansion should be implemented to ensure the standard capacity is not exceeded.

Table 3.2-3 Standard Circuit Capacity of the Distribution Line

Distribution system	Form of leading out		Standard circuit capacity (A)		
	Underground	Overhead	Normal capacity	Emergency (Continuous capacity)	Notes
11kV Overhead	Single Core armored aluminum conductors, 400 mm^2	Grape	350	530	The interconnection points should be provided for one circuit between three other circuits or more.
22kV Overhead	Single Core armored aluminum conductors 500 mm^2	Grape	350	530	As above.
		Grape	65	530	When the interconnection among other circuits is one circuit.

(5) Supply reliability

In principle, no power outage should occur in existing facilities when an N-1 fault[1] occurs during the annual maximum demand of the distribution circuit.

In particular, the load in sound sections, except the failure section of one distribution circuit, has to be supplied during single equipment failure.

(6) Diversity factor of the distribution circuit

The required distribution circuit number meeting the projected area demand should be estimated under diversity factor of 1.27 [2].

(7) Distribution Feeder Protection

The primary voltage line of the distribution system will be protected against short-circuit and earthing faults by the following protection instrument:

(a) Overcurrent Protection at Substation

(i) The Distribution Feeder shall have the following protection at the substation:
(A) Phase-fault protection; and
(B) Earth-fault protection

(ii) Protection shall be provided by circuit breakers operated by relays.

(b) Overcurrent Protection along feeders

(i) The Distribution Feeder shall have overcurrent protection at the tapping point of lateral circuits using Automatic Circuit Reclosers and/or Distribution Fuse Cut-outs

(ii) Automatic Circuit Reclosers and Sectionalizers may be installed to sectionalize the main distribution feeder.

(8) Short-circuit capacity

The maximum permissible short-circuit capacity in the power distribution system is shown in Table 3.2-4 as standard.

Table 3.2-4 Permissible Maximum Short-Circuit Capacity

	Permissible max. value
22kV System	500MVA 13.12kA
11kV System	250MVA 13.12kA

(9) Selection of distribution line route

A passage route of an overhead D/L and the location of each support should be optimally selected considering subsequent matters sufficiently. In particular, the location of poles should be selected for official sites such as road sides in principle.

a. Trend of future demand and system configuration of D/Ls
b. Influence of various disasters
Impact or effect of wind disasters, lightning strikes, flooding, contamination by salt and dust,

1 N-1 fault: Means one circuit failure of transmission line, one bank failure of substation, one circuit failure of the distribution system or one generator failure.
2 Measurement data of distribution feeders in the city of Lae. (Refer to Table 2.7-8)

landslides and land subsidence

c. Concern over the natural environment, social environment and cultural assets etc.
d. Coordination with legal restrictions and various development plans for land use
e. Degree of difficulty of construction and maintenance work
f. Shortening of route length, reduced construction cost by measures such as shortening route length

3.2.3 Formation of Distribution Facilities

(1) System planning

1) Configuration of the distribution system

Overhead distribution system with both 11kV and 22kV should have a radial system applied, which comprises divided sections waving interconnection points respectively.

The division number of one distribution circuit is at least three and each divided section should be able to interconnect with different distribution circuits as a system configuration for flexible system operation.

Sectionalizers capable of interrupting load currents should be installed at major points dividing D/Ls and interconnection points between neighboring circuits for short-term power restoration. A conceptual diagram of the system configuration is shown in Fig. 3.2-1.

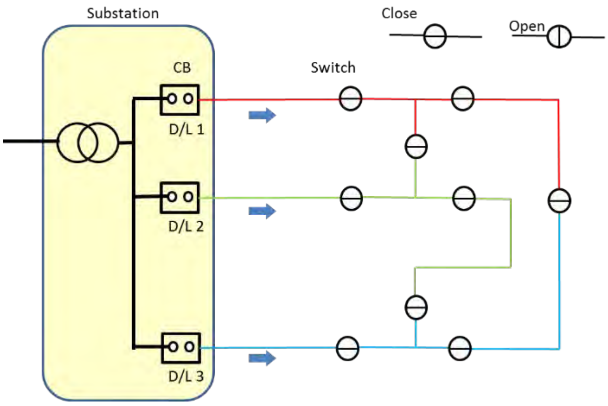


Fig. 3.2-1 Basic System Configuration of Sectionalized System with Interconnection

Furthermore, in addition to the switch, to continue the supply to loads other than the work section when the D/L work and placed ABS (non-load switching) is based on the idea below.

Furthermore, ABSs (Air-Break Switch - Non-load) may be installed in addition to the abovementioned sectionalizer at the following defined point to continue power supply for the sections outside the work section during maintenance or renovation work.

The relieved load capacity (=The benefit capacity) is defined by the following equation:

$$(Pb) = L \times C \ (kVA.\ km)$$

The benefit capacity (Pb) should be at least 10,000 kVA.km.

Where, L : the length of line downstream of the switch but not downstream of any other switch -kVA.

C : the installed kVA upstream of the switch but not upstream of any other operational switchgear-kVA

2) Number of circuits

The number of the distribution circuits is one on a single route.

3) Capacity of the distribution circuit

The capacity of a distribution circuit is limited to the values shown in Table 3.2-3 taking comprehensive account of economic efficiency and capability to lead out feeders.

(2) Facilities planning

Provisions in this section are be applied in common to 11kV and 22kV systems except for the insulation level of equipment and facilities.

1) Part of leading out feeders of the primary substation

Part of leading out feeders[3] of the primary substation should apply the underground cable, taking line reliability and ease of maintenance etc. into account.

It should be noted that there is a case whereby the two-circuits/route is forced for the leading out feeders (load side than 1st pole rising cable) based on constraints on the route.

In this case, the overhead line should be applied as one circuit and the aerial cable should be laid as another on the same route.

Because there is a possibility that the maintenance system for underground cables in PPL cannot correspond quickly to cable faults, an aerial cable should be adopted which is easier than an underground cable for maintenance work.

2) Supports

Supports for overhead power lines should adopt H-shaped steel as standard.

The length of the support should be selected to ensure the necessary clearance of wires from the ground to address the environment for installing lines.

3) Conductors

The conductor size should be selected based on the standard shown in Table 3.2-5 to ensure the supply capacity of lines and proper voltage considering future demand.

3 Part of leading out feeders, means a line from CB in a switchgear board to the first pole of the overhead line

Table 3.2-5 Standard Specification of Typical Conductor

Class of circuit	Conductor type	Conductor code	Ampacity *1) (A)	Impedance (Ω/km)		Notes
				R*2)	X*3)	
Feeders, Express feeder, Interconnected radial feeder	ACSR	Grape	531	0.263	0.324	
Distributors	ACSR	Grape	531	0.263	0.324	
Spurs	ACSR	Cherry	434	0.367	0.337	11 kV Urban line with load over 50kVA
	ACSR	Apple	248	0.901	0.366	11 kV Urban line with load under 50kVA, 22 kV Rural line with load over 50kVA
	ACSR	Raisin	155	2.14	0.378	22 kV Rural line with load under 50kVA

*1) Continuous current carrying capacity, A Rural weather, summer noon, wind speed of 2m/s
*2) AC resistance at 50Hz, 75°C
*3) Inductive reactance to 0.95m between conductors at 50Hz

[Circuit Definition]

The following terms have been used to identify the normal function of different 33kV, 22kV and 11kV circuits:

Feeder	:	A circuit which emanates from a primary substation. These are sometimes referred to as primary feeders.
Express Feeder	:	A feeder with no distribution, interconnections or spurs, terminating at a primary substation.
Interconnector	:	A feeder interconnecting primary substations, but normally operated with one intermediate point open.
Distributor	:	A circuit with interconnecting facilities between feeders, but normally operated with one intermediate point open. These are sometimes referred to as laterals.
Spur	:	A circuit connected to a feeder, interconnector, or distributor at one end only and with no means of interconnection from another circuit. These are sometimes referred to as laterals.
Interconnected Radial Feeder	:	A feeder interconnected to other feeders at several normally open points. The feeders normally operate in a radial mode but can be interconnected in emergency or maintenance conditions to allow sections of the feeder to be isolated and still continue supply in the remaining sections.

4) Switchgear

A sectionalizing switch is installed to facilitate system operation or ease restoration during system faults.

Installation position of sectionalizer (load break switch) is shown in Fig. 3.2-1. The specification is shown in Table 3.2-6. In addition, the specification of ABS (non-load break switch) which is installed to isolate working sections is shown in Table 3.2-7.

Furthermore, switchgear shown in Table 3.2-6 and Table 3.2-7 is applied in common to the 11kV system in the city of Lae and the 22kV system in the suburbs respectively.

This is because although the distribution facilities in the Lae city are operated under a voltage of 11kV, the insulation level is designed for that of 22kV facilities.

Table 3.2-6 Specification of Sectionalizer

Ratings	Rated maximum voltage	27 (kV)
	Rated continuous current	600 (A)
	Fault make capacity	20 (kA-RMS)
	Fault make capacity	50 (kA-Peak)
	Rated full load operations	600 (A)
	Short-term current	20 (kA-RMS) 1sec.
Breaking capacity	Mainly active	600 (A) (at pf = 0.7)
	Cable charging	50 (A)
	Transformer magnetizing	4 (A)

Table 3.2-7 Specification of ABS

Ratings	Rated maximum voltage	24 (kV)
	Rated continuous current	630 (A)
	Fault make capacity	None
	Peak withstand current	50 (kA)
	Rated full load operations	None
	Short-term current	20 (kA-RMS) (800A 3 second)
Breaking capacity	Mainly active	None
	Cable charging	5 (A) for 22kV, 10 (A) for 11kV
	Transformer magnetizing	5 (A) for 22kV, 10 (A) for 11kV

CHAPTER 4

SHORT-TERM DISTRIBUTION NETWORK IMPROVEMENT PLAN IN THE LAE AREA

CHAPTER 4 SHORT-TERM DISTRIBUTION NETWORK IMPROVEMENT PLAN IN THE LAE AREA

4.1 BASIC POLICY TO IMPROVE SHORT-TERM DISTRIBUTION NETWORK

4.1.1 Improved Power Supply Reliability

As described in Chapter 2, to improve the planning for short-term distribution networks, measures to improve power supply reliability have focused on reducing the duration rather than frequency of power outages.

It is not easy to switch the connection of the distribution network in the Lae area, since the capacity and ability of the equipment or the line configuration are insufficient for operation. This status of the distribution facility results in a major restriction, which prevents swift restoration of power outages and flexible network operation.

When a power outage occurs due to any failure in a D/L, once the fault section is identified and isolated from the sound part of the line, power is sent as soon as possible from the substation to the upstream side section, as viewed from the fault point and from the neighboring D/L connected to the downstream section. With the distribution network connection subject to swift switching operation, the index for power supply reliability can be improved.

In the Lae area, when a D/L fault occurs, as described in the restoration step in Section 2.4.3(3) 3), power is sent to the upstream sound sections from the substation, but not from the neighboring section to the other sound section due to some restrictions on network operation imposed by the distribution facility. These include:

- Switchgears on the D/L lacking sufficient ability to make/break load current and make fault current.
- The fact that the interconnection point for an emergency power supply in the event of a fault is not secured in the network.
- The trunk line capacity is not secured for an emergency power supply.

Consequently, all the sound section on the downstream side suffers a power outage pending restoration of the defective equipment, which results in very low reliability of the power supply.

Accordingly, a plan to improve the Lae area distribution network is considered to reduce the duration of power outage by enhancing the weak points that impair network operation.

4.1.2 Improvement of Load Balance among Distribution Lines

(1) Condition of load current in the Lae area feeders

Table 4.1-1 shows the load current record (per hour, for 2014) in each feeder at the Taraka and Milford substations. The supply area for each D/L is shown in Fig. 4.1-1.

Viewing the whole area of Lae, loads are distributed to the Milford substation side, particularly the coastal area. Feeders of the Taraka substation toward a southerly direction (T3, T4 and T5) tend to have heavy load to transfer the heavy load near the Milford area. T4 in particular has a heavy load because it also supplies the factory in the west area. Feeders of the Milford substation toward the coastal area, namely M1, M3 and M5, have relatively high average loads.

Table 4.1-1 Load Record of Each Feeder in the Lae Area (per hour, for 2014)

Substation	Feeder	Hourly Load(MW)		Main supply area
		Average	Peak	
Taraka	T1	1.13	2.56	North-east (University etc.)
	T2	2.17	4.52	North-west
	T3	1.39	4.94	South (connected to Milford)
	T4	**3.34**	**6.45**	West (connected to Milford)
	T5	2.39	4.7	South-west (connected to Milford)
	Average	2.08		
	σ	0.88		
Milford	M1	2.49	4.56	South (including Taiheiyo Cement)
	M2	1.69	4.38	East
	M3	2.62	**6.05**	South-east
	M4	**2.78**	6.01	South-west
	M5	1.76	4.56	North-east
	M6	1.11	4.25	West (toward Nadzab)
	Average	2.08		
	σ	0.65		

Source: JICA Study Team

Source: JICA Study Team

Fig. 4.1-1 Supply Area Map of Existing Distribution Lines in LAE

(2) Reflection on the distribution network design

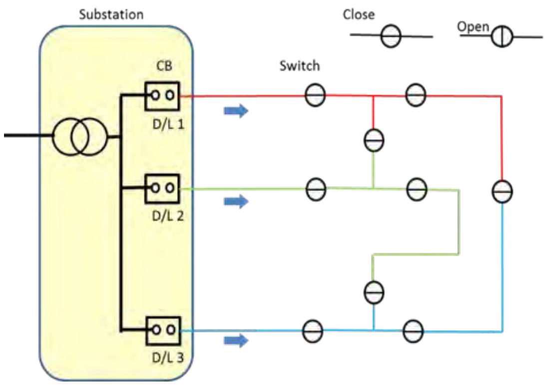
A well-balanced load current among the distribution feeders is generally preferred for the following reasons:

- Ease of load management of the D/L
- Loss reduction in the trunk line
- Ease of voltage management
- Ease of network switching when restoring faults

This is true when every D/L is assumed to have the same configuration model, line length and load distribution. In the actual distribution network however, the load current is imbalanced due to the geographical condition of the supply area (shape, area, existence or absence of roads) and/or that of the growth of new loads in the area.

Regarding the Lae area, D/Ls from the Taraka substation supply power up to near the Milford substation out of necessity, which is inappropriate as a form of distribution network. Accordingly, when examining efforts to re-configure the distribution network, work to extend the line from the Taraka substation is limited to the extent required to ensure the load balance and network connection between both substations. When there is a section which enables the rebalance of feeder currents by transferring load, this is also reflected in the reconfiguration of the distribution network.

4.2 CONSTRUCTION DESIGN TO IMPROVE THE DISTRIBUTION NETWORK



Source: JICA Study Team

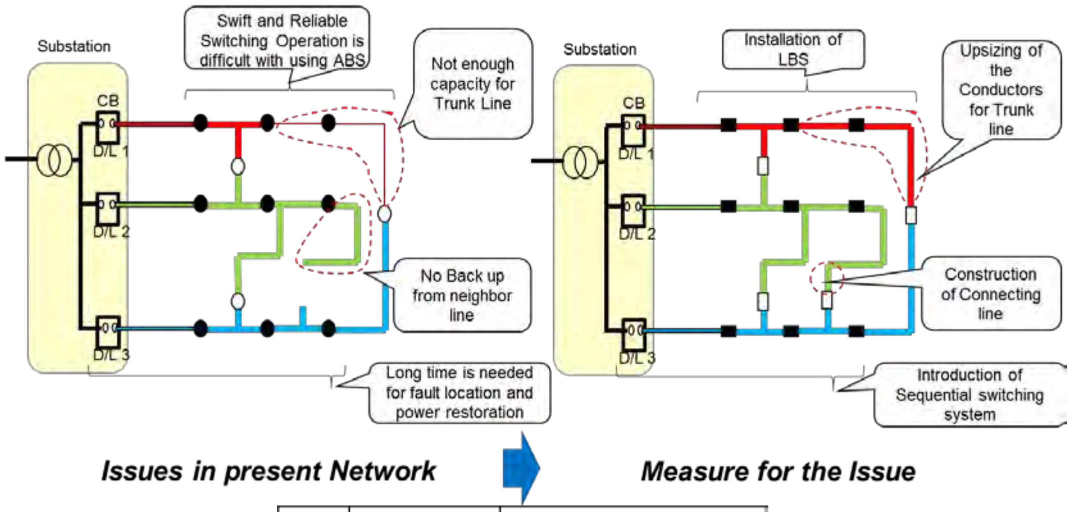
Fig. 4.2-1 Basic System Configuration of the Sectionalized System with Interconnection

Measures to solve issues affecting D/Ls in the Taraka and Milford substation area are examined based on rules governing the configuration of the distribution network as described in Chapter 3 and the basic policy in 4.1 of this Chapter. Based on data of D/L faults and the condition of the existing facility, to reduce the duration required to restore power, it is effective to install switchgears with load-break/load-make capacity and introduce a network configuration comprising divided sections with respective interconnection points, as described in Chapter 3. The reliability of a D/L can be improved by increasing the number of sections divided and interconnection points, but taking into account the network in the Lae area and the construction cost, it is appropriate to sectionalize each D/L into three and install two interconnection points. Fig. 4.2-1 shows the network configuration.

To realize the network, an outline of which is shown in Fig. 4.2-2, it is necessary to implement four items as follows:

1. Installation of a LBS
2. Introduction of Sequential switching system
3. Construction of an Interconnection Line
4. Upsizing of Conductors for the trunk line

For each item, the background issues in D/L, countermeasures and the result of the construction design are described below.



	On load operation	Role of Switchgear	
		Sectionalize (Close)	Tie (Open)
ABS	Inappropriate (over capacity)	●	○
LBS	Available	■	□

Fig. 4.2-2 Measures for Distribution Network to improve Power Supply Reliability

4.2.1 Installation of the LBS (Load-Break Switch)

(1) Distribution line issues

In the Lae area, ABS (Air Break Switches, as shown in Fig. 4.2-3) are installed in the D/L for switching, which originally lack the capacity for load current interruption. Conversely, LBS (Load-Break Switches, as shown in Fig. 4.2-4) are not installed in the D/L, which is a measure against impairing ease of operation and supply reliability.

To use ABS for distribution network switching, whole line sections must be de-energized for each operation by opening the circuit breaker at the substation. However, operating the distribution network accordingly is ineffective for practical use because it raises the frequency of power outage and significantly complicates the steps involved in switching operation procedures.

In fact, ABS in the Lae area is operated for a charged network by necessity. In other words, non-standard operation is conducted by PPL as part of daily work, which is problematic as follows because of the unregulated operation.

1) When the switch interrupts / closes the load current, the arc damages the surface of the metal contact parts, which leads to contact resistance at the contact point and triggers ABS burn accidents.

2) There is no guarantee or assurance of low contact resistance since the certainty of operation varies in accordance with the skill of the operator. That also triggers ABS burn accidents.

3) In case the load current is large, additional procedures such as the separation of distribution transformers are needed to decrease the load current before opening operation, which prevents swift network switching.

4) Since ABS is equipment of the outdoor exposure type, the contact points suffer directly from rain and dust, rendering them prone to faults. As a result of the ABS structure, as well as inappropriate operation as described, ABS is considered prone to frequent faults.

On searching for fault points in the D/L, the fault section can be narrowed down by reclosing the fault current with switchgears such as sectionalizers. However, this method cannot be used for the D/L in the Lae area because ABS lacks capacity to close the fault current.

(2) Planned Remedial Measures

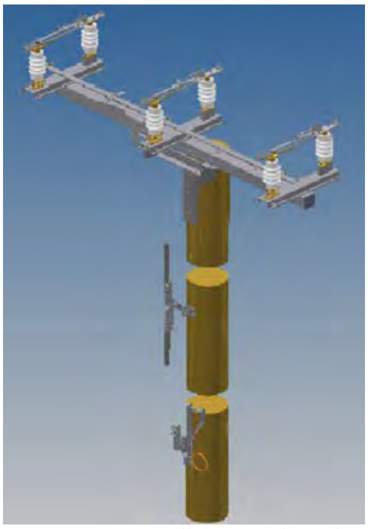
LBSs should be installed to main points in the trunk line and interconnection line to conduct swift and reliable make/break operation. Standard number of LBS per one 11kV D/L is shown in Table 4.2-1 and their installation positions are examined adequately according to the configuration of each distribution network

LBS should not be of the air insulation / break type but rather the gas insulation type, to ensure reliable switching operation and equipped with an interrupter allowing closing load current and fault over current.

Table 4.2-1 Standard Number of LBS per 11kV Distribution Line

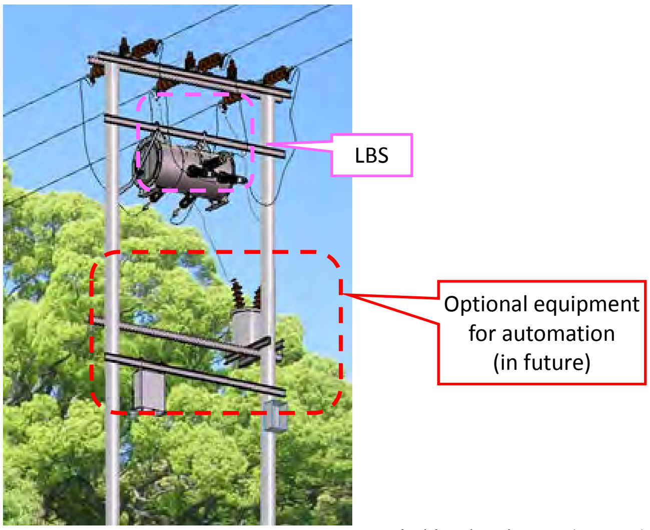
Role	Number of installations	Remarks
Feeder sectionalizer	1	To enable an emergency power supply for the first section at fault occurrence, since considerable time is required to locate and restore the underground feeder cable from substation in case fault exists there.
Trunk line sectionalizer	2	Sectionalizers should be arranged to divide and effectively balance the load of the D/L.
Interconnection switch	3	An interconnection switch should be arranged to enable a flexible power supply from the neighboring D/L in the event of any fault. (total installation number is counted as half, since this switch is connected to two D/Ls).

Examples of the basic pole fitting style of ABS and LBS are shown in Fig. 4.2-3 and Fig. 4.2-4 respectively.



Source: ABB Australia Pty. Ltd Outdoor Side Break Disconnector/Switch SERIES 'S'

Fig. 4.2-3 An Example of Basic Pole Fitting Style of ABS

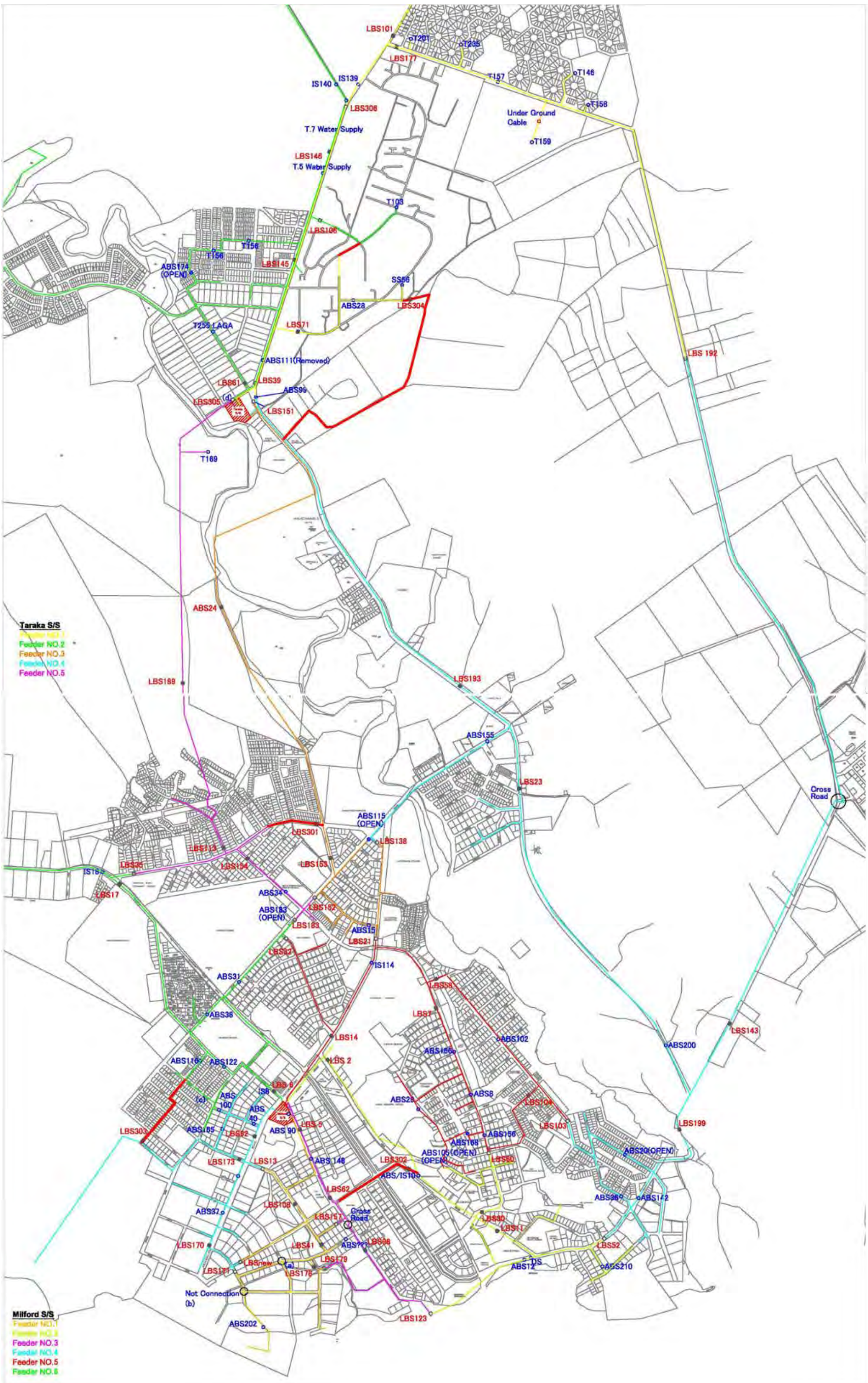


Source: Nisshin Electric. Co. (JAPAN)

Fig. 4.2-4 An Example of Basic Pole Fitting Style of LBS

(3) Construction design

A location map of LBS installation is shown in Fig. 4.2-5, while Table 4.2-2 shows the number of LBS designed to be installed.



Source: JICA Study Team

Fig. 4.2-5 Location Map of LBS Installation (Each LBS site is indicated in red letters)

Table 4.2-2 Number of LBS Designed to be installed

Substation	Feeder No.	Sectionalize	Tie *
Taraka	T1	3	5
	T2	4	3
	T3	2	5
	T4	4	6
	T5	3	5
	T6		
	T7		
	Subtotal	16	24
Milford	M1	3	5
	M2	3	4
	M3	3	4
	M4	3	4
	M5	3	4
	M6	3	5
	M7		
	M8		
	Subtotal	18	26
	Total①	34	50
r②		× 1	× 0.5
Total number of installations (Total ① × r ②)		34	25
		59	

* The number of “Tie” LBS is counted on both sides of the feeder.

Source: JICA Study Team

(4) Cost of construction

1) Calculation conditions

The cost of construction is calculated according to the following conditions:

- Unit construction price, including material price alone, is calculated based on a reference estimation by a manufacturer.
- To deal with any potential surcharges, which could be levied according to the detailed design result, 10% of the construction cost subtotal is added to cover construction contingencies.

2) Summary of Construction Cost Estimate

The construction cost estimate is summarized in Table 4.2-3.

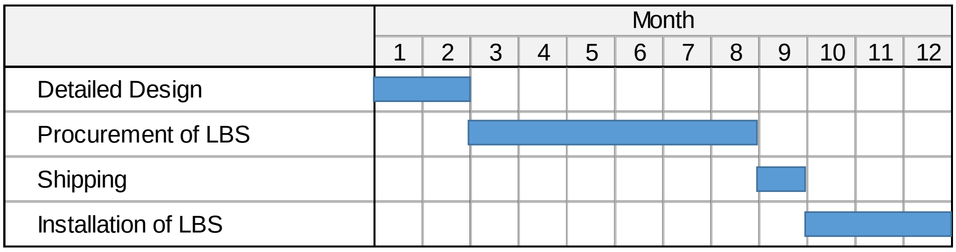
Table 4.2-3 Cost of LBS Installation

Item	Quantity	Unit Price	Amount (kina)	Amount (Yen) [45 Yen/Kina]
Material cost (LBS)	59 Units	40,000 kina/unit	2,360,000	106,200,000
Cost of transportation (POM to Lae) and installation	10%	(Material cost)	236,000	10,620,000
Cost of Supervisor by manufacturer	30 Days	3333 kina/day	100,000	4,500,000
Cost of Supervisor's Trip	2 Trips	6,667 kina/trip	13,333	600,000
Subtotal			***2,709,333***	***121,920,000***
Contingency (10%)			270,933	12,192,000
Total			**2,980,266**	**134,112,000**

Source: JICA Study Team

(5) Schedule

Table 4.2-4 Construction Process to Upgrade Switchgear



Source: JICA Study Team

4.2.2 Sequential Switching System

(1) Background and purpose of the introduction of this system

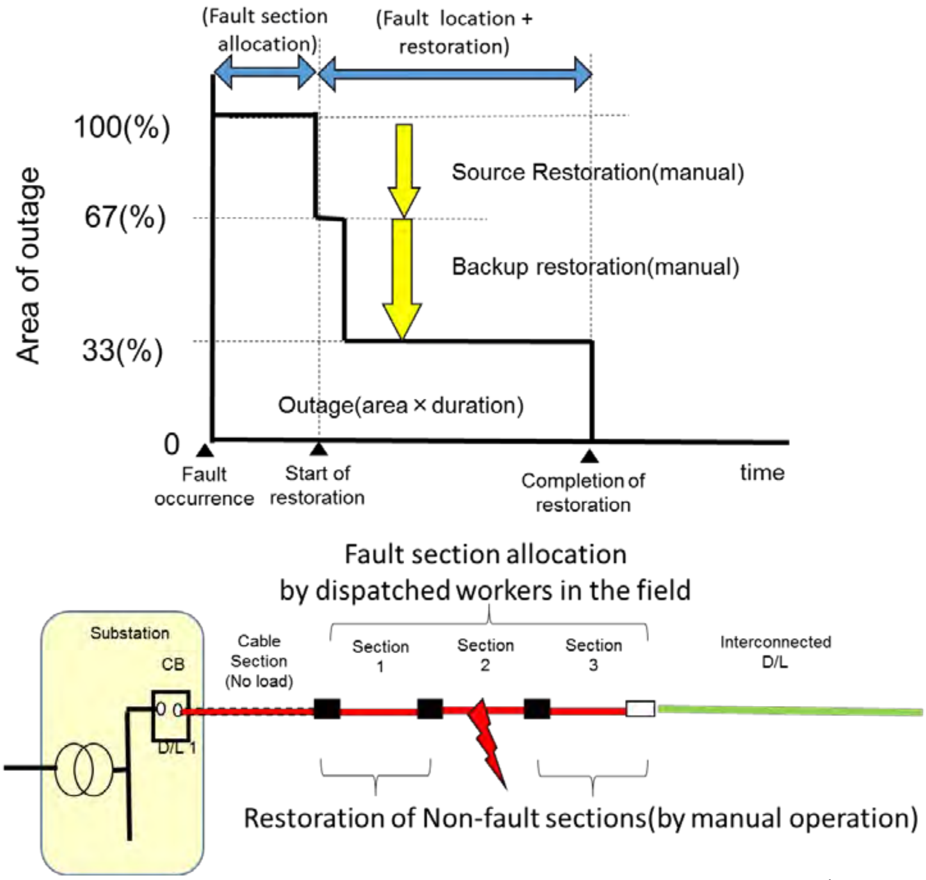
The installation of an LBS enables a swift and reliable restoration of supply to the non-fault section by manual operation of the LBS when a fault occurs. This enables a higher-reliability power supply, as the overview in Fig. 4.2-6 shows.

The sequential switching system is constructed based on this LBS-installed distribution network by adding "automatic isolation of fault section" and "automatic power restoration" functions when a fault occurs. The introduction of this system enables further reduction of outage duration, which in turns helps improve the power supply reliability, as the overview in Fig. 4.2-7 shows.

< Merits of introducing a sequential switching system >

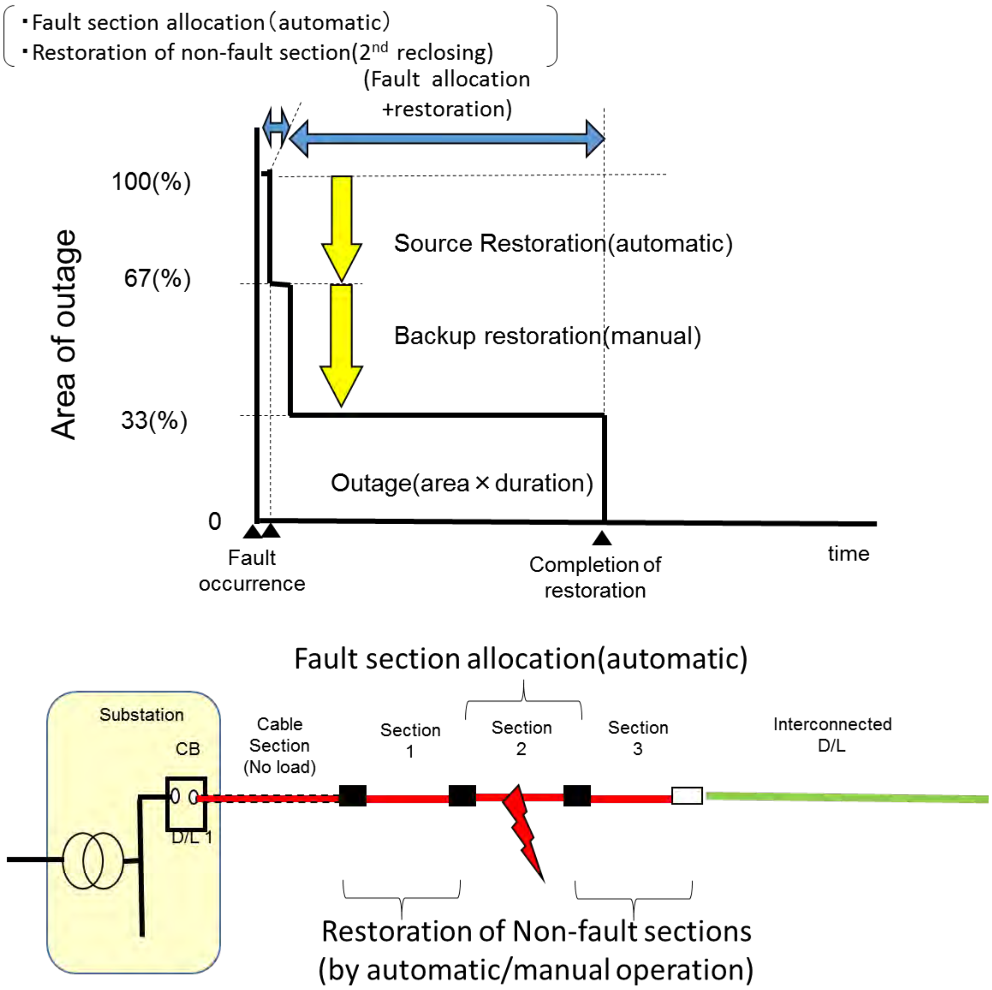
- Fault sections can be located quickly (in several minutes) and automatically
- Power can be restored for the non-fault sections on the source side quickly and automatically. (Power cannot be restored in the present distribution network before allocation of the fault section on site.)

  The time for fault location can be reduced because the fault section is previously located and the area for investigation is narrowed.



Source: JICA Study Team

Fig. 4.2-6 Overview of Fault Restoration by Manual Network Operation

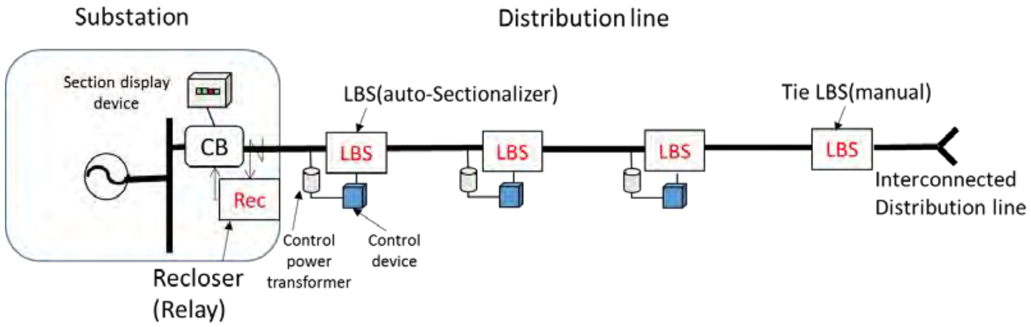


Source: JICA Study Team

Fig. 4.2-7 Overview of Fault Restoration by Network Operation using a Sequence Switching System

(2) System configuration

The configuration of the sequential switching system is shown in Fig. 4.2-8. Each Sectionalizing LBS is utilized as an automatic sectionalizer for this system by connecting sequential the switching control device (hereinafter referred to as the "control device") and transformers for the control device (hereinafter referred to as the "control transformers"). The section display device is equipped in the substation to indicate the automatically located fault section. These equipment components are operated with the coordination of a reclosing relay system to enable the automatic allocation of fault sections and automatic power restoration of the source side non-fault sections. The operation of this system is based on the sequential motion of each device according to the time setting. Communication facilities are not required for the operation of this system.



Source: JICA Study Team

Fig. 4.2-8 Configuration of the Automatic Sectionalizing System (with an automatic source restoration function)

(3) Operation sequence of the system

1) Motions of the CB and LBS when a fault occurs

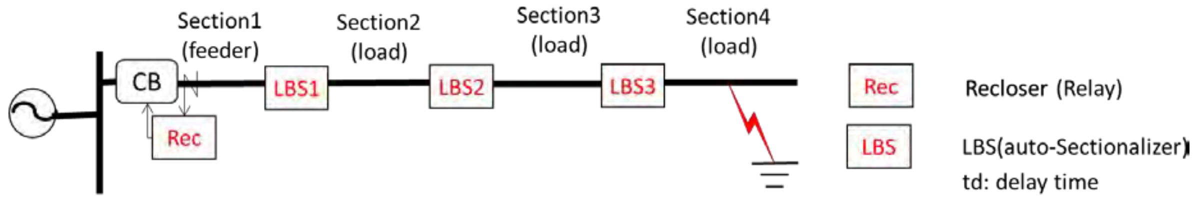
As in the D/L model shown in Fig. 4.2-9, assume that three automatic sectionalizing LBS's are sectionalizing a D/L into one feeder section and three load sections. Fig. 4.2-10 shows an example of the motions of the CB and LBS when a fault occurs in the 4th section of the D/L.

When a fault occurs in the D/L and a protection device in the substation operates to cut off the CB, every automatic sectionalizing LBS on the fault D/L opens by detecting non-voltage of the line. The control device has a mechanism that orders the LBS to close the circuit automatically after a preset delay time (Td) from power charge detection.

LBS1 is charged when the CB is reclosed for a certain time after a fault occurs. LBS1, LBS2, and LBS3 sequentially close the circuit with the interval of preset delay time (Td). When LBS3, which is located on the source side of the fault section, closes the circuit, the fault current flows again and the CB opens. Consequently, LBS1, LBS2, and LBS3 autonomously open again upon detecting the non-voltage of the line.

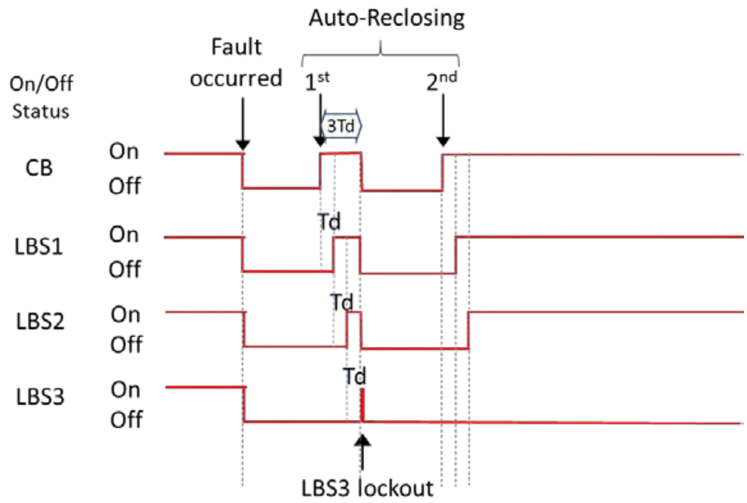
When LBS3 opens after the 1st reclosing, LBS3 locks up to separate the fault section by detecting the condition that drop-off to zero voltage in the line voltage just after (within the preset detection time) it is closed. Following this sequence, the power supply to sections 1, 2, and 3 is restored by the 2nd automatic reclosing of the CB in the substation.

The section display unit in the substation detects the fault section by counting the time (S) between the 1st reclosing of the CB and the 2nd CB trip. Since the CB turns off just after the time required for these three LBS's to turn on ('Td" x 3) in this case the fault section is judged as in section 4.



Source: JICA Study Team

Fig. 4.2-9 Distribution Line Model (the fault point is in section 4 in this case)



Source: JICA Study Team

Fig. 4.2-10 Example of the On/Off Status Chart of the CB and LBS after a Fault Occurs

2) Functions required for the equipment composing the sequential switching system

The functions required to configure the equipment for the sequential switching system are shown in Table 4.2-5.

Table 4.2-5 Functions required to configure the Equipment for the Sequential Switching System

Equipment	Function
LBS	Non-voltage open, short circuit closing, on load switching
Control device	Time detection, sequential switching on, reverse charge lock, collision prevention, delayed open
Section Display device	Fault section decision / display

Source: JICA Study Team

The control device has the following functions related to operation timing.

(1) Turn-on time: time required to turn on the LBS after the control device is charged (e.g., 10 Seconds).

(2) Detection time: time after the LBS is turned on. The LBS is locked out with the status open if the power is turned off during this period. (e.g., 5 Seconds)

(3) Open delay time: to avoid malfunction of the sequential switching system by an instantaneous power off or voltage drop of the source voltage or breakage of the short-circuit current at the LBS, the LBS should stay in an on-status in this period even though the power is lost (e.g., 1 Second).

3) Introduction of automatic backup restoration (Reference)

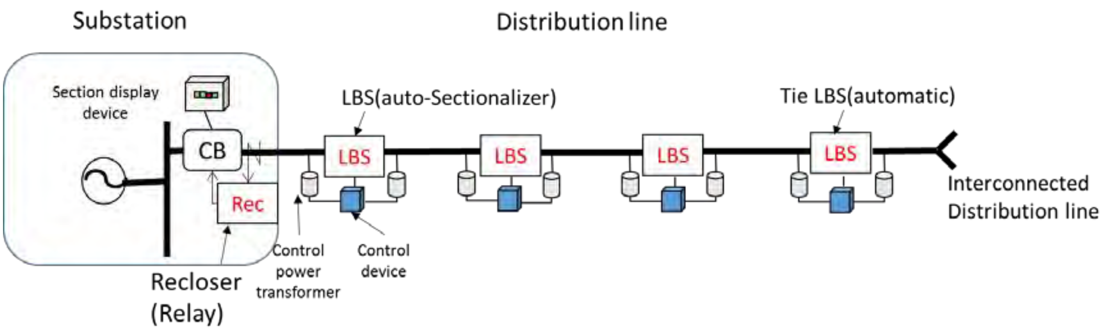
The introduction of an automatic backup restoration can be considered for the D/L, which requires a high-reliability power supply. After a fault occurs in the D/L and power is restored to the source side of the fault section by sequential switching and two sequential reclosing operations, this system automatically supplies power from the interconnection line by turning on the interconnection LBS to the load side section in some preset period (i.e., one minute after finishing the 2nd reclosing).

However, the Introduction of automatic backup restoration seems premature in the short – term distribution network improvement plan, for the following reasons.

Network drawings are not yet appropriately managed in the Lae area,
Enough practical experience with networks with automatic source restoration is required,
Improvement of reliability at generation and transmission side is required[1].

Fig. 4.2-11 is the configuration diagram of this system. By taking this system configuration, each LBS can sense the charge status on both the substation and load side in order to enable restoration by the load side supply. The equipment necessary to add this function to the D/L consists of one control device and two control transformers for each interconnection LBS and one distribution transformer for each sectionalizing LBS.

Higher level management and operation of the distribution network is necessary to introduce an automatic backup restoration in addition to simple automatic source restoration. Since load switching is automatically carried out regardless of the actual load on the D/Ls, for example, an unexpected overload on the D/Ls creates a risk of fault expansion to the interconnection line. To prevent this situation, the load of the power D/Ls has to be managed with sufficient accuracy or the network has to be operated with a sufficient allowance. At the same time, sufficient measures must be taken to ensure the safety of the fault recovery work at the site. This can be done, for example, by accurately grasping the present form of each D/L.



Source: JICA Study Team

Fig. 4.2-11 Configuration of the Sequence Switching System (with an automatic source and backup restoration function)

(5) Introduction plan

Introduction plan of Sequential Switching System (Source restoration and Backup restoration) shows bellows.

As mentioned above, backup restoration system does not including Short - term distribution network improvement plan. The timing of introduction of backup restoration to the Lae area is

1 At the leader of the distribution line in Lae area, UF (under frequency) relays are installed in the present. The life of LBS's may be shortened when the UF relays frequently operate the CB's in the substations more than expected by the effect of power outages from the power source side, such as faults on the transmission lines and isolations of the generators.

considered premature.

1) Overview of the introduction plan

- Subject area: Substation area of Taraka and Milford, where high demand density and high reliability are required for D/Ls
- Equipment quantities for Construction:

Table 4.2-6 Equipment Quantities for Construction of the Sequential Switching System

Equipment	Place of installation	Quantity		
		For source restoration	For backup restoration	Total
Control device	-For source restoration: sectionalize LBS (each unit) -For backup restoration: tie LBS (each unit)	34 Units	25 Units	59 Units
Control power transformer	-For source restoration: sectionalize LBS (each unit) -For backup restoration: sectionalize LBS (each 2 units) + tie LBS (each unit)	34 Units	84 Units	118 Units
Section display device	-Taraka 5 units -Milford 6 units	11 Units	0 Unit	11 Units

Source: JICA Study Team

2) Schedule

The schedule for the construction for source restoration is shown in Table 4.2-7 and that for backup restoration is shown in Table 4.2-8.

Table 4.2-7 Schedule for Construction (source restoration)

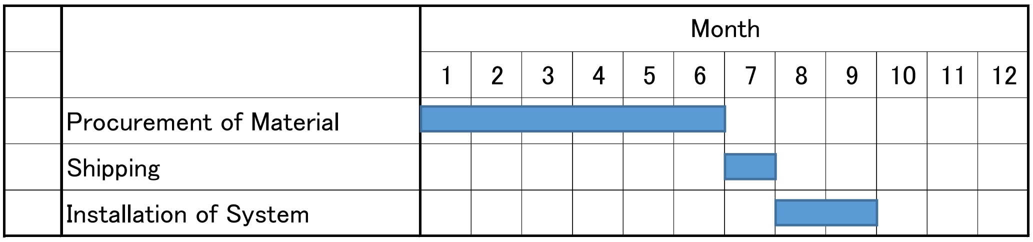
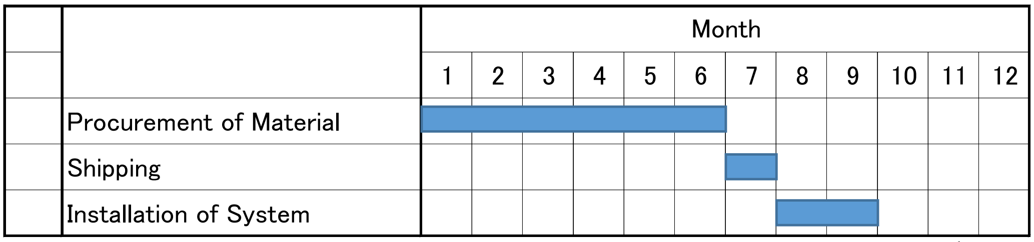


Table 4.2-8 Schedule for Construction (backup restoration): Reference



Source: JICA Study Team

3) Cost of construction

The cost of construction for source restoration is shown in Table 4.2-9 and that for backup restoration is shown in Table 4.2-10.

Table 4.2-9 Cost of Construction (source restoration)

Item	Volume	Unit price	Amount (Kina)	Amount (Yen) (Assumptions 45 JPY /Kina)
Material cost (control device)	34 Units	8,889 Kina/unit	302,222	¥13,600,000
Material cost (control power transformer)	34 Units	6,978 Kina/unit	237,244	¥10,676,000
Material cost (section display device)	11 Units	5,556 Kina/unit	61,111	¥2,750,000
Cost of transportation (POM to Lae) and installation	Subtotal of Material cost * 10%		63,533	¥2,859,000
Cost for Supervisor dispatched by manufacturer	30 Days	3,333 Kina/day	100,000	¥4,500,000
Cost of Supervisor's Trip	2 Trip	6,667 Kina/trip	13,333	¥600,000
Contingency Preliminary expenses (10%)			77,397	¥3,482,860
Total			**851,366**	**¥38,311,465**

Source: JICA Study Team

Table 4.2-10 Cost of Construction (backup restoration): Reference

Item	Quantity	Unit price	Amount (Kina)	Amount (Yen) (Assumptions 45 JPY /Kina)
Material cost (control device)	25 Units	8,889 Kina/unit	222,222	¥10,000,000
Material cost (control power transformer)	84 Units	6,978 Kina/unit	586,133	¥26,376,000
Material cost (section display device)	0 Units	5,556 Kina/unit	0	¥0
Cost of transportation (POM to Lae) and installation	Subtotal of Material cost * 10%		89,422	¥4,024,000
Cost for Supervisor dispatched by manufacturer	30 Days	3,333 Kina/day	100,000	¥4,500,000
Cost of Supervisor's Trip	2 Trip	6,667 Kina/trip	13,333	¥600,000
Contingency Preliminary expenses (10%)			100,252	¥4,511,360
Total			**1,102,776**	**¥49,624,940**

Source: JICA Study Team

4.2.3 Construction of the Interconnection Line

(1) Issues in the distribution line

Some of the sections in the distribution network cannot receive power from neighboring D/Ls due to the lack of interconnection lines for the section

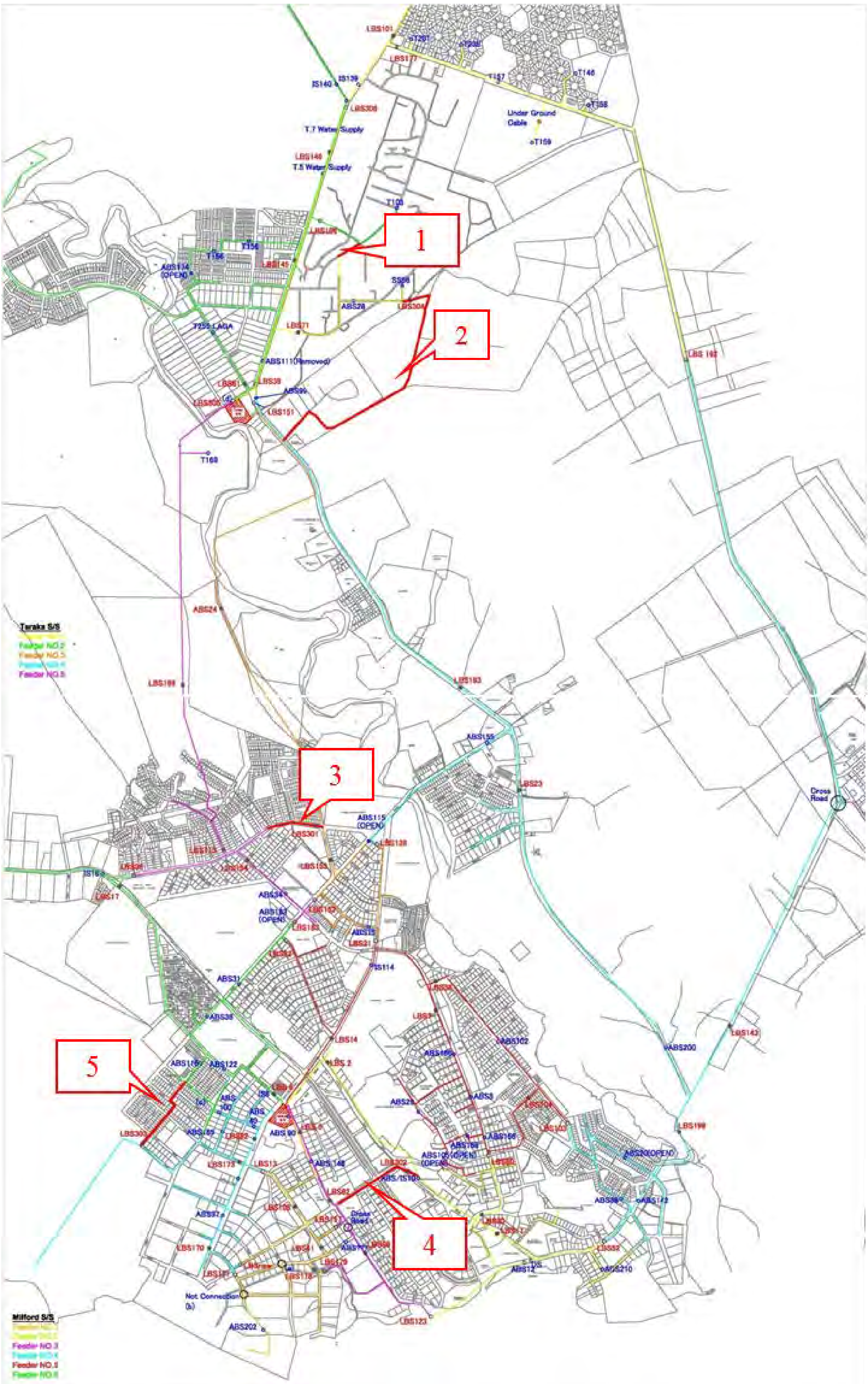
(2) Planned Remedial Measures

- In the examination of reconfiguration of distribution network, interconnection lines using standard size conductor of ‘Grape’ are constructed to enable power supply from at least three neighbor D/Ls. With this measure, uniform current trunk line capacity is ensured from substation to the interconnection point for neighbor D/L on the far end.

- As a basic point to consider, the D/L should be constructed in public land such as public road.

(3) Construction design

A location map of construction of the interconnection line is shown in Fig. 4.2-12.
The construction length of the interconnection lines is shown in Table 4.2-11.



Source: JICA Study Team

Fig. 4.2-12 Location Map of Interconnection Line Construction

Table 4.2-11 Construction Length of Interconnection Line

No.	Substation	Feeder	Construction Length (km)	Purpose
1	Taraka	T1	0.17	- To ease the load on T2 - To enhance the connection between T1 and T2.
2		T4	2.00	- To secure a backup supply for T1 (university load) - To enhance the trunk line capacity toward the western area.
3		T5	0.41	- To enhance the connection between T3 and T5
4	Milford	M3	0.66	- To enhance the connection between M2 and M3
5		M6	0.61	- To enhance the connection between M4 and M6
Total		**5**	**3.83**	

Source: JICA Study Team

(4) Cost of construction

1) Calculation conditions

The cost of construction is calculated according to the following conditions:

- "Length of conductor" is calculated, based on "Length of the construction route", with a 10% allowance for taking sag and detour in accordance with the shape of the road into consideration, as follows:

"Length of conductor" = "length of the construction route" × 3 (phases) × 1.1

- The unit construction price is calculated based on the past construction track record in PPL.
- To deal with potential surcharges according to the detailed design result, 10% of the subtotal construction cost is added to cover construction contingencies.

2) Summary of Construction Cost Estimate

The cost estimates for construction are summarized in Table 4.2-12.

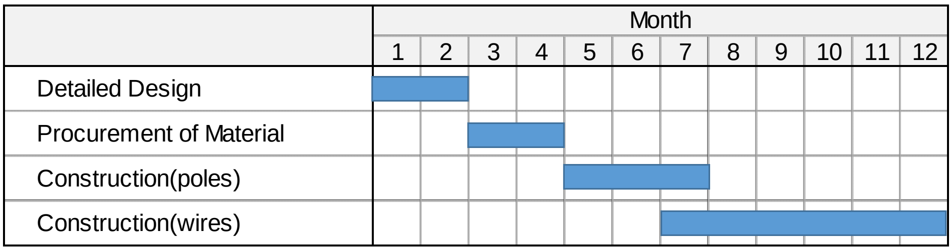
Table 4.2-12 Construction Cost of the Interconnection Line

Item	Quantity	Unit Price	Amount (kina)	Amount (Yen) [45 Yen/Kina]
Distribution General Cost Estimate, Urban Setting (Medium Voltage 3-phase, including Labor, Transport & Accommodation)	3.83 km	90,000 kina/km	344,700	15,511,500
Material cost (Grape Conductor, 3 phases)	12.60 km	6000 kina/km	75,600	3,402,000
Subtotal			***420,300***	***18,913,500***
Contingency (10%)			42,030	1,891,350
Total			**462,330**	**20,804,850**

Source: JICA Study Team

(5) Schedule

Table 4.2-13 Construction Process of the Interconnection Line



Source: JICA Study Team

4.2.4 Replacement of Trunk Line Conductor

(1) Distribution line issues

Some of the sections in the trunk line (including major interconnection lines) lack sufficient capacity because the existing conductors are smaller than standard. Those sections disturb the operation of the distribution network, since load-switching restrictions apply.

(2) Planned Remedial Measures

When examining the reconfiguration of the distribution network for each D/L, conductors on the root of the trunk line are designed to be replaced with those of the standard 'Grape' size.

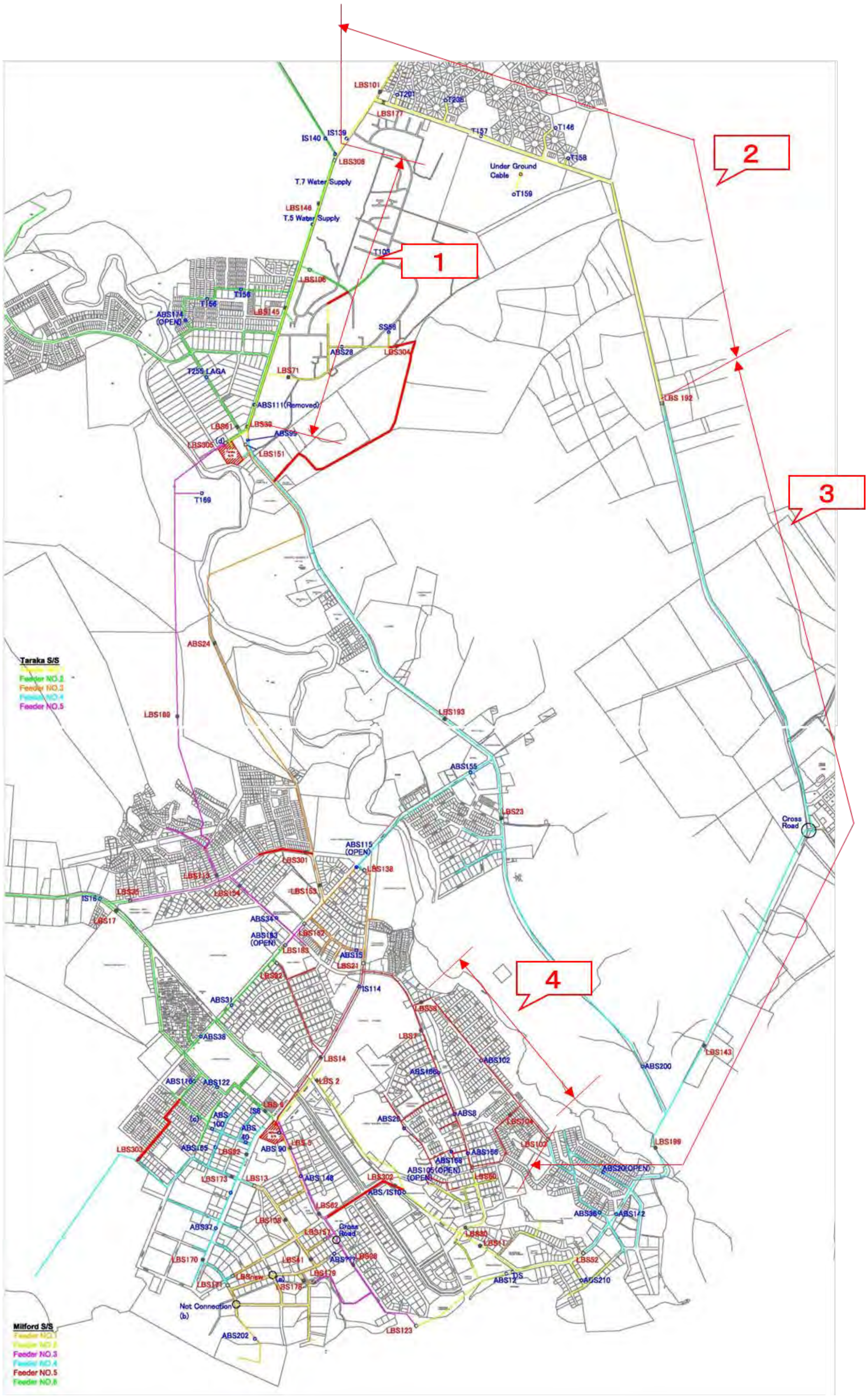
(3) Construction design

A location map for replacement trunk line conductors is shown in Fig. 4.2-13, with construction lengths shown in Table 4.2-14.

Table 4.2-14 Construction Length of Replacement Trunk Line Conductor

No.	Substation	Feeder	Existing wire	Construction Length (km)	Object of construction
1	Taraka	T1	Banana	3.40	- To secure trunk line capacity and enhance the connection between T1 and T4.
2		T2	Banana, Apple, Cherry	4.05	- To secure trunk line capacity (This line is a branch of T2 for now but there are plans to use it as a T1 trunk line) and enhance the connection between T2 and T4.
3		T4	Banana, Cherry	5.65	- To secure the trunk line capacity
4	Milford	M5	Banana	2.00	- To secure the trunk line capacity and enhance the connection between M5 and T4.
Total				**15.11**	

Source: JICA Study Team



Source: JICA Study Team

Fig. 4.2-13 Location Map of Replacing Trunk Line Conductor

(4) Cost of construction

1) Calculation conditions

The cost of construction is calculated according to the following conditions:

- “Length of conductor” is calculated, based on “Length of the construction route” with 10% allowance for taking sag and detour in accordance with the shape of road into consideration, as follows:

“Length of conductor” = “length of the construction route” × 3 (phases) × 1.1

- Unit construction price is calculated based on the previous construction track record in PPL.
- To deal with potential surcharges according to the detailed design result, 10% of the subtotal construction cost is added to cover construction contingencies.

2) Summary of Construction Cost Estimate

The construction cost estimate is summarized in Table 4.2-15.

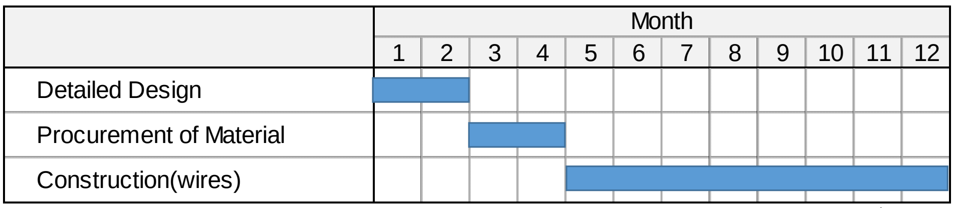
Table 4.2-15 Cost of Replacing Trunk Line Conductors

Item	Quantity	Unit Price	Amount (kina)	Amount (Yen) [45 Yen/Kina]
Distribution General Cost Estimate, Urban Setting (Medium Voltage 3-phase, including Labor, Transport & Accommodation)	15.11 km	90,000 kina/km	1,359,900	61,195,500
Material cost (Grape Conductor, 3 phases)	49.90 km	6000 kina/km	299,400	13,473,000
Subtotal			***1,659,300***	***74,668,500***
Contingency (10%)			165,930	7,466,850
Total			**1,825,230**	**82,135,350**

Source: JICA Study Team

(5) Schedule

Table 4.2-16 Construction Process for Replacing Trunk Line Conductors



. Source: JICA Study Team

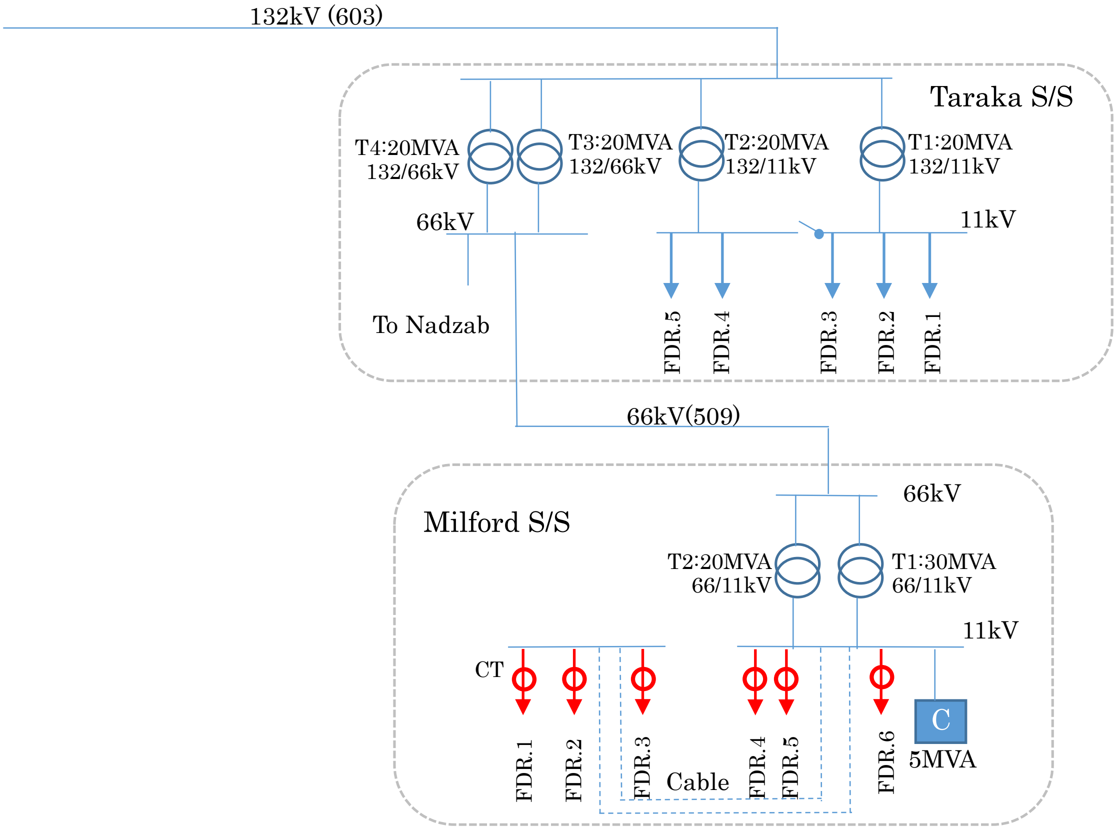
4.2.5 Milford Substation 11kV Switchgear Replacement

As described above, there are proposals to replace conductors on the trunk line root with 'Grape' conductors, which is the standard size in the Lae area. According to the conductor specification sheet, the rated current of the 'Grape' conductors is 531A. To eliminate load-switching restrictions, not only D/Ls must have sufficient capacity, 11kV switchgears and 11kV power cables in the substation outlet must also have sufficient capacity.

Measures in substations with short-term improvement plans are considered in this Chapter.

(1) Existing capacity of 11kV facilities in the substation

Fig. 4.2-14 shows a single line diagram of Taraka and Milford substations. Table 4.2-17 shows the existing capacity of 11kV facilities in Taraka and Milford substations. The capacity of the facilities highlighted in red is smaller than that of 'Grape' conductors.



Source: JICA Study Team

Fig. 4.2-14 Taraka and Milford Substation 11kV Single Line Diagram

Table 4.2-17 Existing Capacity of 11kV Facilities in Taraka and Milford Substations

Substation	11kV feeder power cable	11kV circuit breaker	CT for distribution feeder
Milford	350A *	800A	400A
Taraka	760A *	1250A	1200A

*Estimate from the catalog

Source: JICA Study Team

Considering the capacity of 531A, 11kV facilities such as switchgears and power cables in Taraka substation have sufficient capacity. However, 11kV feeder power cables and CTs for the distribution feeder in Milford substation lack sufficient capacity compared to 531A and must therefore be replaced.

(2) Replacement of 11kV switchgears in Milford substation by PPL

The substation team in PPL Lae office also consider it necessary to replace 11kV facilities in Milford substation and had already planned to do so, due to aging. The switchgear equipment is now 40 years old and prone to numerous malfunctions. The capacity is upgraded with the replacement due to the aging and a budget for the same has already been prepared. An outline of the replacement plan is shown below.

1) Replacement schedule

Fig. 4.2-15 shows the replacement schedule and Fig. 4.2-16 shows a single line diagram in the Milford substation after replacement.

The replacement plan comprises four phases, each of which is shown as an outline below.

Phase 1 .....The existing load of feeders 4, 5 and 6 in the Milford substation is transferred to other feeders in Taraka and Milford substations.

Phase 2 .....Power cables connected to existing 11kV switchgears are removed.

Phase 3 .....The existing 11kV switchgears are removed.

Phase 4 .....The new 11kV switchgears are constructed.

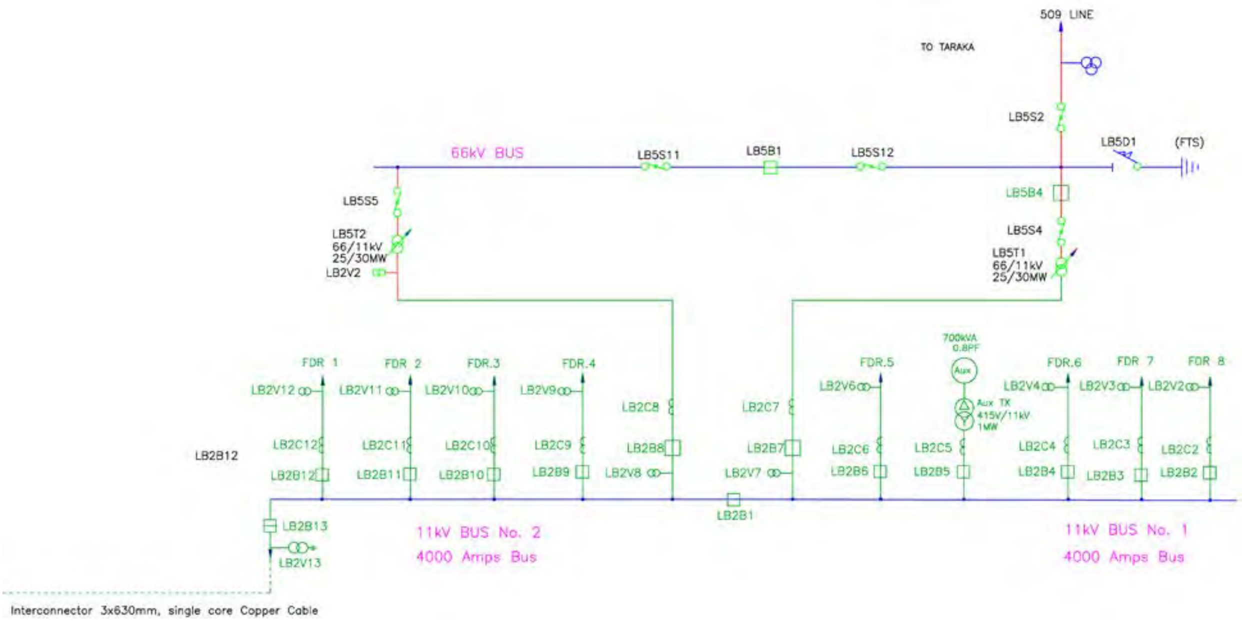
Initially, the replacement would be carried out after load-switching because the new 11kV switchgears would be installed at the same place as existing equipment. However the replacement process has been changed and the new 11kV switchgears are now to be installed elsewhere, following the interview in April 2015. Only the process has been changed and Fig. 4.2-16 has not been changed.

The below schedule schedules replacement for 2015. However, the replacement will not be completed until 2016 due to the delay in planning.

◆ Milford Upgrade casual Work Plan	0	2014/09/15	2015/10/02
◆ Milford Upgrade casual's Work Plan	1	2014/09/15	2015/10/02
◆ Phase 1	2	2014/09/15	2014/12/10
Preparation of materials & equipments	3	2014/09/15	2014/10/13
Decommission of Feeder 4, 5 & 6	4	2014/10/14	2014/11/11
Digging of New Underground Cables for Feeders 4, 5 & 6	5	2014/11/12	2014/ 12/10
◆ Phase 2	6	2014/12/11	2015/03/12
Preparation of materials & equipments	7	2014/12/11	2015/01/08
Assist to dig and relocate Tx1 and Tx2 LV u/grouncl cables	8	2015/01/09	2015/01/28
Assist to install new u/ground Cables for Txl and Tx2	9	2015/01/29	2015/02/17
Assist for the civil works & installation of new 66kV CB for Tx1	10	2015/02/18	2015/02/26
Disconnection of existing interconnectors form bus 1, 2, 3, & 4	11	2015/02/27	2015/03/12
◆ Phase 3	12	2015/03/13	2015/06/08
Assist to removing all aging panels	13	2015/03/13	2015/04/10
Digging of u/ground Feeder Cable for Feeder 1, 2, 3 & 7	14	2015/04/13	2015/05/11
Assist to relocate Aux/Genset and Cap Bank	15	2015/05/12	2015/06/08
◆ Phase 4	16	2015/06/09	2015/10/02
Assist to install of new switchgears	17	2015/06/09	2015/07/20
Assist to install new u/cables	18	2015/07/21	2015/09/14
Assist for testings and commissioning	19	2015/09/15	2015/10/02

Source: PPL

Fig. 4.2-15 Milford S/S 11kV Switchgear Replacement Schedule



Source: PPL

Fig. 4.2-16 Milford Substation Single Line Diagram after the Replacement

2) Cost information

The budget for the replacement is 3.9 Million Kina, from PPL's own funds.

3) New capacity of 11kV facilities in the Milford substation

Following the replacement, the capacity of the 11kV power cables will be upgraded to 760A and that of the 11kV switchgears will be upgraded to 1250A. The capacity of CTs for the feeder will be upgraded to 1200A.

As a result, 11kV facilities in Milford substation will have sufficient capacity compared to 531A after the replacement.

(3) Need for Substation Measures

Table 4.2-18 shows the capacity of 11kV facilities in Taraka and Milford substations after the replacement.

Table 4.2-18 Capacity of 11kV Facilities in Taraka and Milford Substations after the Replacement

Substation	11kV feeder power cable	11kV circuit breaker	CT for distribution feeder
Milford	760A (*1)	1250A	1200A
Taraka	760A (*1)	1250A	1200A

*Estimate from the catalog
Source: JICA Study Team

The measures in substations with a short-term improvement plan are not necessary because 11kV facilities in Taraka and Milford substations after the replacement will have sufficient capacity compared to the distribution.

4.3 FIGURE OF THE DISTRIBUTION LINE IN 2020

(1) Required number of distribution lines in 2020 in accordance with demand forecast

To calculate the required number of D/Ls in 2020 based on the demand forecast.

The load and required number of D/Ls for each substation based on the demand forecast are shown in Table 4.3-1.

Table 4.3-1 Transition Table of Required Quantity of Distribution Lines is based on the Demand Forecast of 2014-2020

	Year	2014	2015	2016	2017	2018	2019	2020
Demand Load (MW) (A)	Milford	20	21	22	24	27	29	32
	Taraka	18	20	21	22	24	27	29
	Nadzab/Erap	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Total	39	41	43	46	51	56	62
MVA (Conversion) (PF=0.85) (B)	Milford	24	25	26	28	31	35	38
	Taraka	21	24	25	25	28	31	34
	Nadzab/Erap	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Total	45	49	51	54	60	66	73
Transformer Capacity (MVA) (C)	Milford	50	50	50	50	50	50	50
	Taraka	40	40	40	40	40	40	40
	Nadzab/Erap	1	1	1	1	1	1	1
	Total	91	91	91	91	91	91	91
Max.Load of Distribution line (MVA) (D)	Milford	30	31	33	36	40	44	48
	Taraka	27	30	31	32	36	40	43
	Nadzab/Erap	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Total	58	62	65	69	76	84	92
Required number of distribution line (PF=0.85) (E)	Milford	5	5	5	6	6	7	8
	Taraka	5	5	5	5	6	6	7
	Nadzab/Erap	1	1	1	1	1	1	1
	Total	11	11	11	12	13	14	16

Source: JICA Study Team

A = Demand Load in 2014-2020

B = Demand Load is converted to MVA B = (A) ÷ 0.85 (Power Factor)

D = Maximum Load of each D/L at each Substation
= B × 1.27 (D/L Diversity Factor in Chapter 2)

E = Required Number of D/Ls E = D ÷ 6.74

6.74MW = Rated Power Transmission Capacity per D/L
= 11kV × 354A (Rated Current per 1 D/L) × √3 ÷ 1000

The calculated result with these introductions in mind is as shown in Table 4.3-1.

The maximum load of Taraka & Milford is 38 MW in 2014 and will be about 1.6 times 62MW in 2020.
Accordingly, the number of D/Ls required for Taraka & Milford in 2020 will be 15 circuits, namely an increase of four lines.

(2) The factors behind the increased demand load of the distribution line

The factors behind the increased load are as follows:

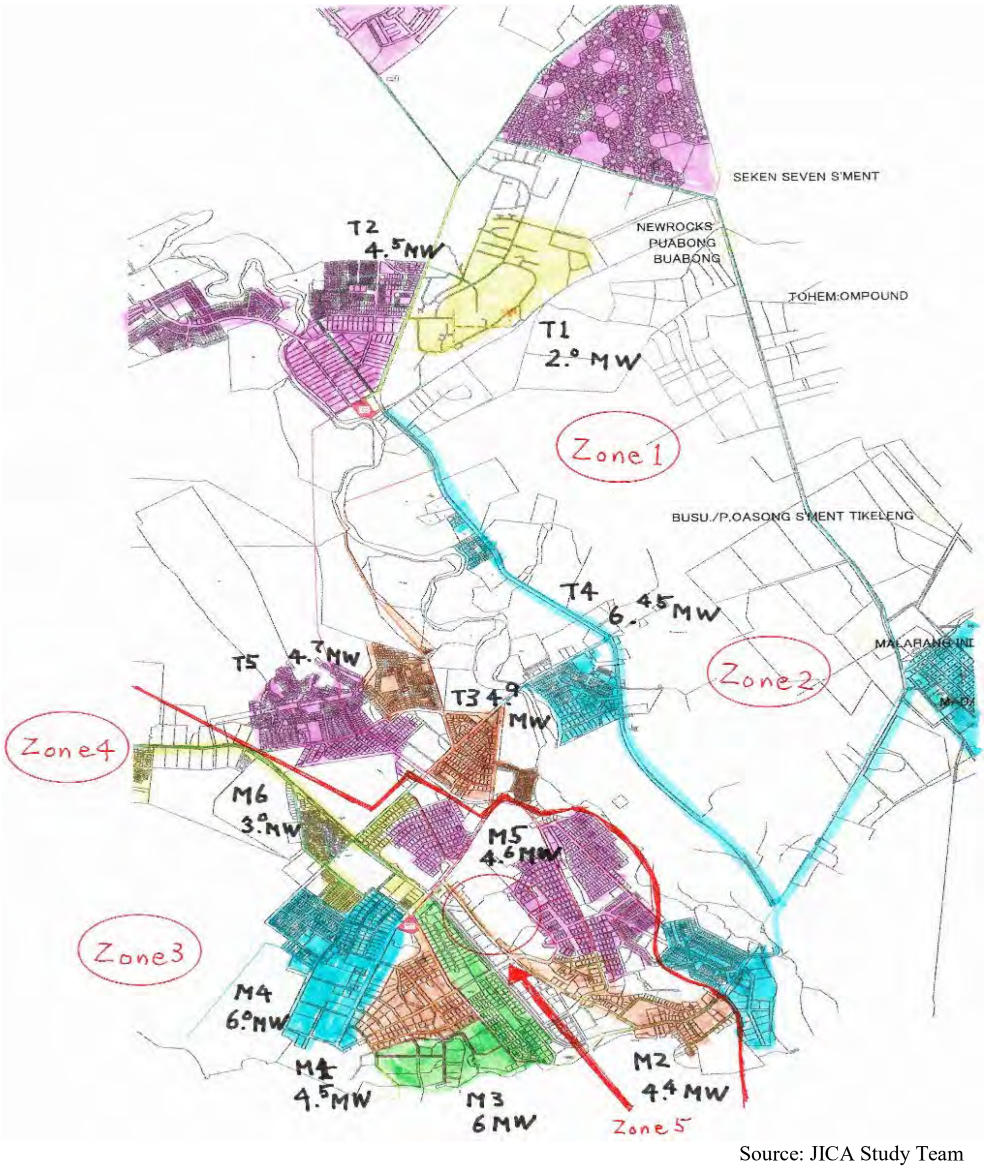
1. Load increases due to the increased demand load per customer
2. Load increase due to supplying new customers with electricity

The main factor behind increased demand up to 2020 can be considered the load increase due to the increased number of new customers.

(3) Prediction of increased load area

The supply area and peak load of each D/L in 2014 are shown in Fig. 4.3-1.

Colorless parts show no-load areas as of now



Source: JICA Study Team

Fig. 4.3-1 Supply Area and Peak Load of Each Distribution Line in 2014

These zones are estimated as follows (shown as Table 4.3-2) in 2020

Table 4.3-2 Forecast Zone Type

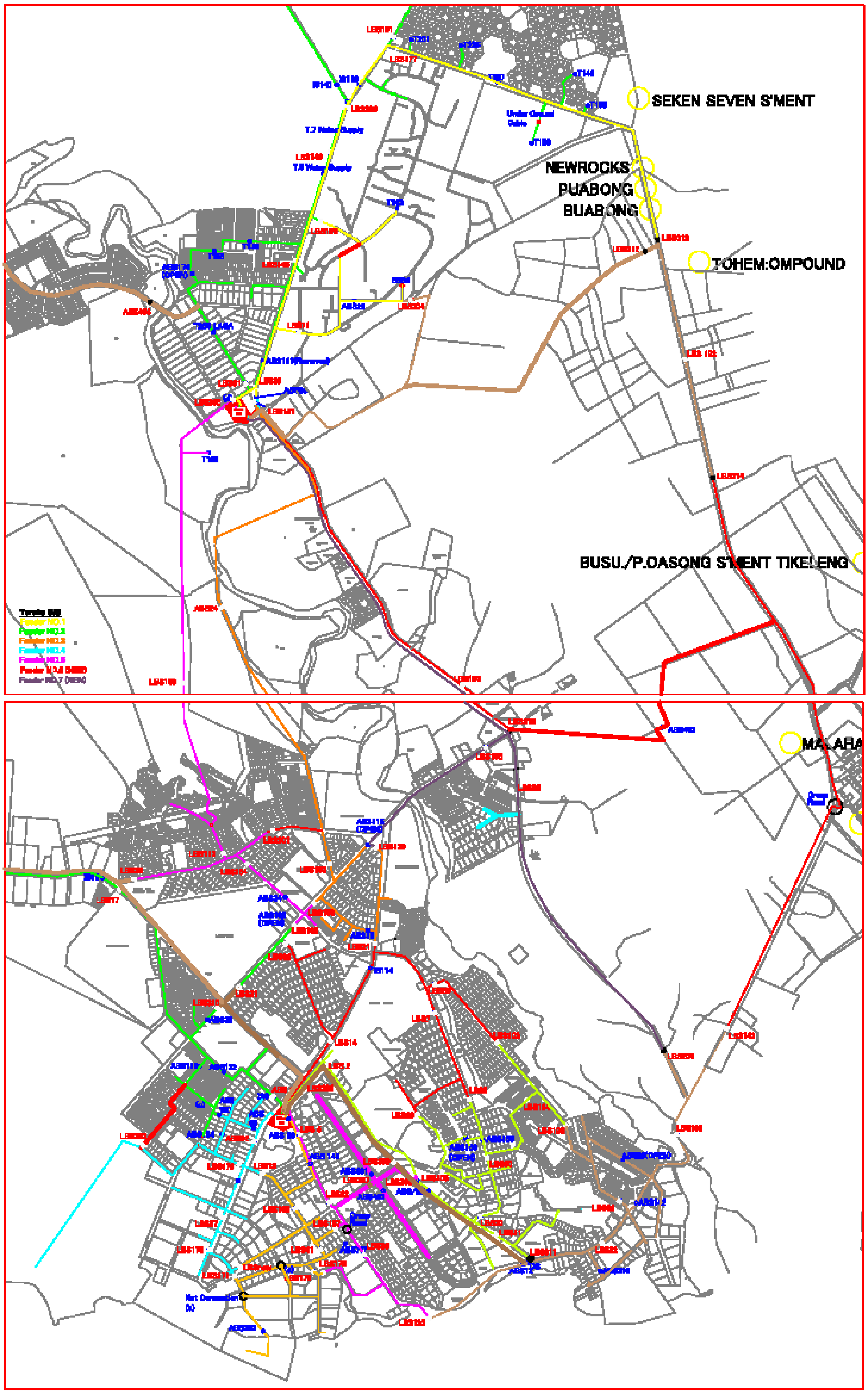
	Situation in 2014	Situation in 2020
Zone 1	Vacant lot, household	Factory, household
Zone 2	Vacant lot, household	Factory, household
Zone 3	Vacant lot, household	Factory
Zone 4	Factory, Vacant lot, household	Factory, household
Zone 5	Vacant lot	Shopping center

* Note: Zone 4 means the planned industrial park and household area along the Highland Highway

Soruce: JICA Study Team

(4) Required Design of D/L in 2020.

The study results and design are as follows:



Source: JICA Study Team

Fig. 4.3-2 Distribution Line Map in 2020