GEOFF BROWN & ASSOCIATES LTD

PERFORMANCE BASED RATE SETTING

REVIEW OF FORECAST CAPITAL EXPENDITURE FOR THE SECOND REGULATORY PERIOD

DAVAO LIGHT AND POWER COMPANY (DLPC)

Prepared for

ENERGY REGULATORY COMMISSION

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EXECUTIVE SUMMARY

TOTAL CAPEX

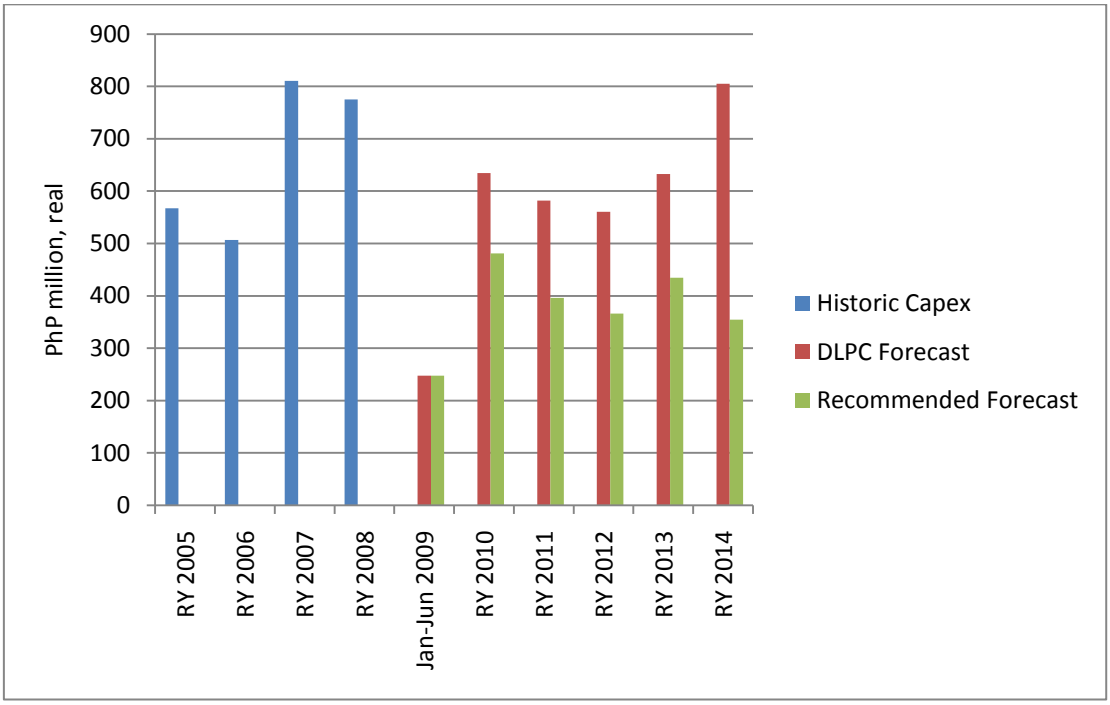
A comparison of our recommended total CAPEX with DLPC's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of DLPC Forecast and Recommended CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
DLPC Forecast	247.67	634.52	581.82	560.40	632.88	805.26	2,580.36
Recommended Forecast	247.67	481.30	396.11	365.91	434.59	354.45	1,551.06
Adjustment		(153.22)	(185.71)	(194.49)	(198.29)	(450.81)	(1,029.30)
Impact of Adjustment		(24%)	(32%)	(35%)	(31%)	(56%)	(40%)

A comparison of our recommended and DLPC's forecast CAPEX with DLPC's actual CAPEX over the historical period CY 2005-08 is shown in the figure below.

Comparison of Forecast, Recommended and Historical Total CAPEX



MAJOR PROJECTS

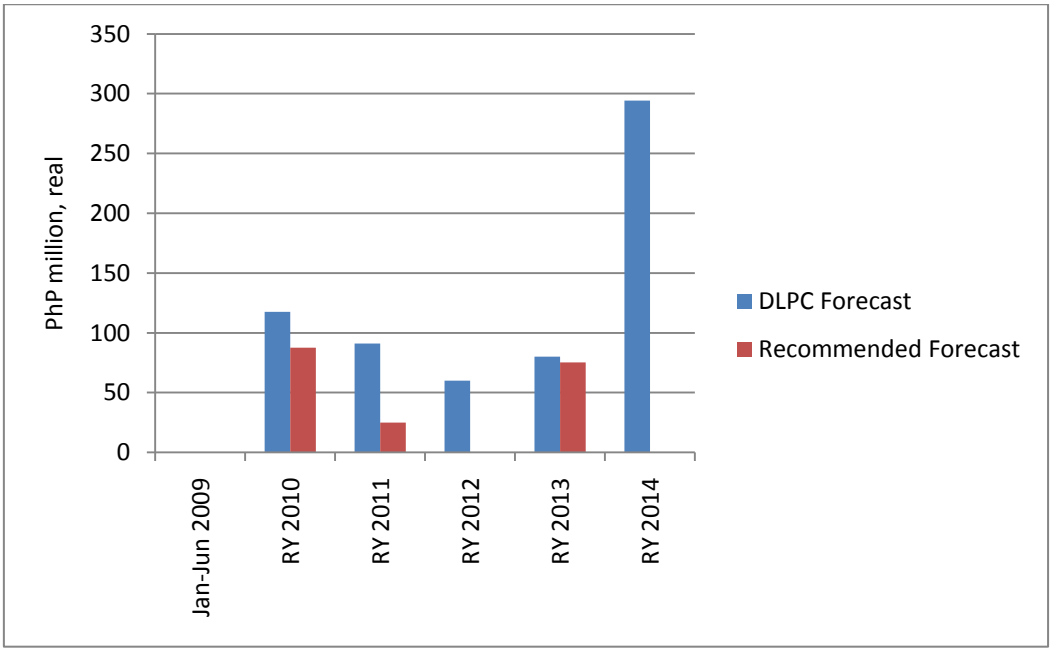
A comparison of our recommended total major project CAPEX with DLPC's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of DLPC's Major Project Forecast and our Recommended Major Project CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
DLPC Forecast		117.47	91.05	60.06	80.06	294.10	525.27
Recommended Forecast		87.47	25.00		75.40		100.40
Adjustment		(30.00)	(66.05)	(60.06)	(4.66)	(294.10)	(424.87)
Impact of Adjustment		(26%)	(73%)	(100%)	(6%)	(100%)	(81%)

A comparison of our recommended major project CAPEX with DLPC's forecast is shown in the figure below.

Comparison of Recommended and Forecast Major Project CAPEX



Our recommended adjustments to the individual projects are summarized below.

- We recommend that no provision be made in the CAPEX forecast for the purchase of the Digos line from NGCP as ERC still has to rule on DASURECO's opposition to the sale proceeding. We also note that the amount included in the forecast was PhP30.00 Million, whereas the agreed purchase price was only PhP15.29 Million. Should this transaction proceed before the end of the second regulatory period, we suggest the cost be recovered through a retrospective adjustment to DLPC's approved CAPEX for the third regulatory period.

- We recommend that the provision for the new administration building in the CAPEX forecast be reduced to PhP25.00 Million because a significant portion of the existing building does not require replacement. Our recommended CAPEX should be sufficient for DLPC to replace the wooden portions of the existing building with a new concrete structure with a size of up to 1000 m^2.

- We recommend that the installation of a new transformer at Sta. Ana substation be deferred from RY 2011 to RY 2013.

- We recommend that the construction of the new Maa, Mintal and Buhangin substations not be included in the forecast as our analysis indicates that the utilization of existing power transformer capacity across the DLPC network is low. We recognize that the Mintal substation is intended to reinforce relatively long distribution feeders (by DLPC standards) but

the loading on these feeders is low and we consider any power quality issues can be managed.

- We recommend that the proposed new Magtuod 138 kV switching station not proceed as the second line to supply the ERA substation is not programmed for construction until the third regulatory period. We also note that there are issues in relation to the operation of this asset that first need to be resolved with NGCP.

RESIDUAL RENEWAL CAPEX

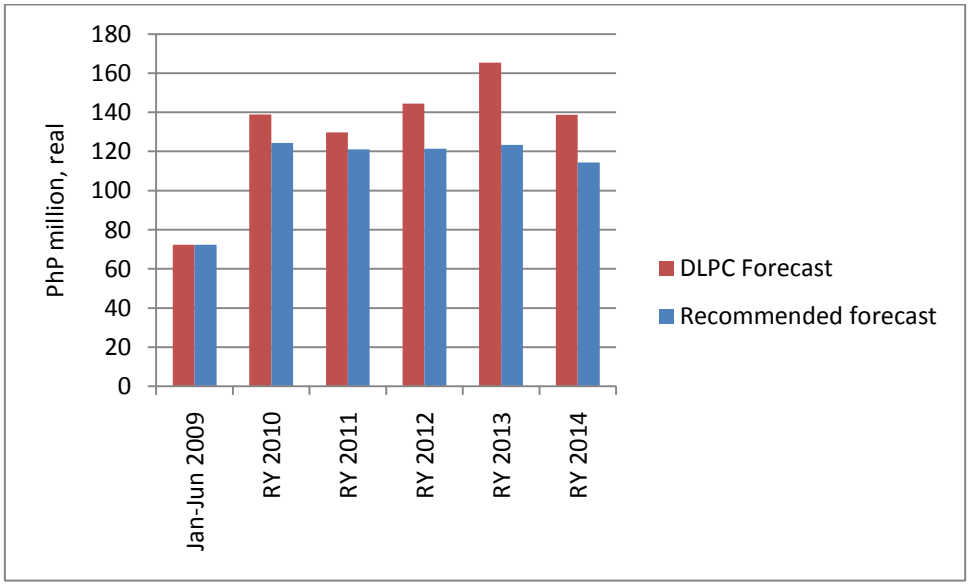
A comparison of our recommended residual renewal CAPEX with DLPC's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of DLPC Forecast and Recommended Residual Renewal CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
DLPC's Forecast	72.28	138.94	129.8	144.48	165.38	138.69	578.35
Recommended Forecast	72.28	124.29	120.98	121.37	123.36	114.32	480.03
Adjustment		(14.65)	(8.82)	(23.11)	(42.02)	(24.37)	(98.32)
Impact of Adjustment		(11%)	(7%)	(16%)	(25%)	(18%)	(17%)

A comparison of our recommended residual renewal CAPEX with DLPC's forecast is shown in the figure below.

Comparison of Recommended and Forecast Residual Renewal CAPEX



We recommend that DLPC's forecast CAPEX for the replacement of station equipment be reduced, based on an analysis of the average equipment age of the assets compared to the regulatory asset lives used in the SKM asset valuation. While DLPC provided a detailed description of its proposed renewal program, this appeared to reflect an underlying assumption that constraints on renewal CAPEX were relatively low. We also recommend reductions to DLPC's forecast CAPEX for the renewal of power operated equipment based on a similar analysis.

We recommend that CAPEX for the provision of a new asset and works management system be deferred until the third regulatory period. We consider that it is unrealistic for DLPC (or other APC utilities) to plan to install and integrate new works and asset management software at the same time as installing new SCADA software, since both systems require extensive input from technical staff to accurately populate the databases on which they rely. Deferring the purchase and implementation of

the works and asset management system will allow the DLPC to focus on properly implementing the new system only after the SCADA software is fully operational.

RESIDUAL GROWTH CAPEX

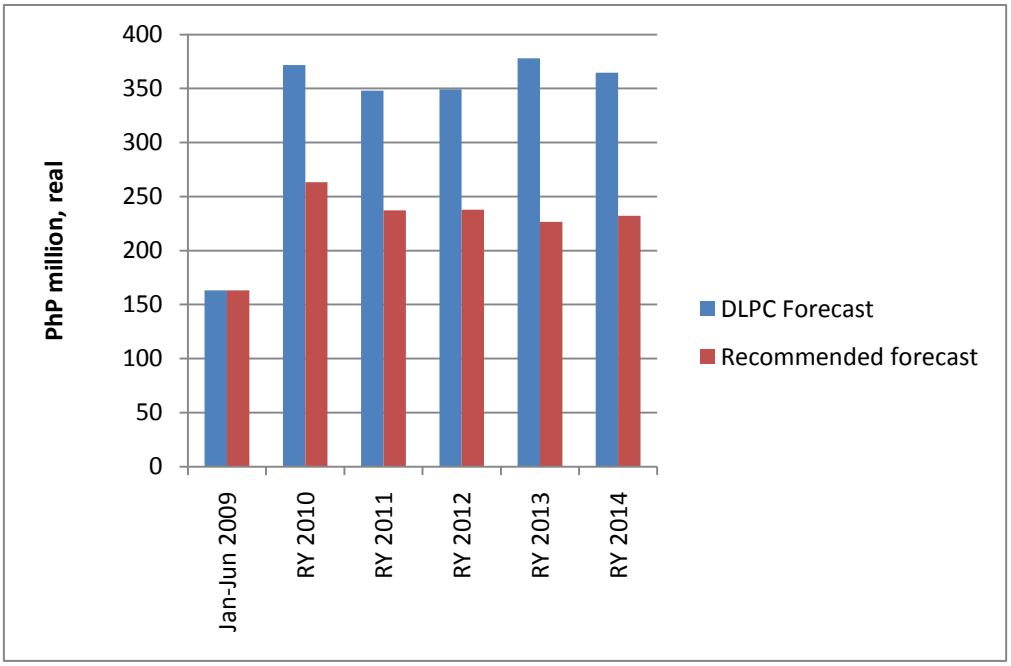
A comparison of our recommended residual growth CAPEX with DLPC's forecast for the period January 2009 to June 2014 is shown in the table below.

Comparison of DLPC Forecast and Recommended Residual Growth CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014	Total (RY 2011-14)
DLPC Forecast	163.14	371.81	348.14	349.12	378.08	364.58	1439.92
Recommended	163.14	263.25	237.29	237.81	226.47	232.24	933.81
Adjustment		(108.56)	(110.85)	(111.31)	(151.61)	(132.34)	(506.11)
Impact of Adjustment		(29%)	(32%)	(32%)	(40%)	(36%)	(35%)

A comparison of our recommended residual renewal CAPEX with DLPC's forecast is shown in the figure below.

Comparison of Recommended and Forecast Residual Growth CAPEX



Our recommended adjustments to DLPC's residual growth CAPEX forecast are summarized below.

- We recommend that a provision of PhP27.09 Million in RY 2013 upgrading the power transformer at Pampanga substation be removed from the forecast. As noted above, DLPC's utilization of power transformers across its network is low and we consider that DLPC can defer this upgrade by better utilizing its existing capacity.

- We recommend significant reductions to DLPC's residual growth expenditure on substation equipment. DLPC has not justified this expenditure in its revenue application. As the utilization of DLPC's existing substations and distribution feeders is low, we see little need to increase the capacity of its existing plant.

- We recommend expenditure of PhP5.00 Million for laboratory equipment in RY 2014 be removed from the forecast. This was a one-off expenditure item that was not explained in the forecast.

- We recommend a reduction of PhP13.65 Million to the forecast fit out cost for DLPC's proposed new customer service center at the SM Mall as the forecast cost was based on a rate that Asian Appraisal considered excessive.

- We recommend reductions to a range of other growth related line items, where CAPEX is driven by growth in peak demand, since we considered DLPC's forecast demand growth to be high.

- We also recommend reductions to the forecast CAPEX for line transformers and consumer metering equipment as our assessment is that the installed cost of this equipment will remain constant in real terms over the forecast period.

RESIDUAL REFURBISHMENT CAPEX

We did not review DLPC's residual refurbishment expenditure as it was not a material component of its total forecast CAPEX.

1. INTRODUCTION

The Energy Regulatory Commission (ERC) is currently implementing a performance-based form of regulation (PBR) for investor owned electricity distribution utilities in the Philippines. Under the PBR framework a distribution utility will be subject to a cap on the average price that it may charge for the delivery of distribution wheeling services. This price cap is reset in advance of each four (4) year regulatory period using the building block approach described in the Rules for Setting the Distribution Wheeling Rate (RDWR), which was released by the ERC on December 8 2008[1]. It takes the form of a price path that specifies the maximum average price (MAP) that a regulated utility may charge in each year of the regulatory period.

The entry of distribution utilities into the PBR process has been staggered into four (4) entry points and the reset process for the setting of the price cap for the six (6) utilities entering PBR at the third entry point is currently underway. This process will result in the setting of the price path for each utility for a regulatory period that commences on July 1 2010 and terminates on June 30 2014. This regulatory period is specified in the RDWR as the second regulatory period[2].

The ERC has published a Position Paper, also dated December 8 2008, which sets out in some detail how the price reset process for the third entry point utilities will be undertaken[3].

An important requirement of this reset process is the review of the capital expenditure (CAPEX) forecasts submitted by the utilities in the revenue applications that have been submitted in accordance with the requirements of the RDWR and the Position Paper. CAPEX over the second regulatory period will impact the size of the regulated asset base (RAB), which will in turn impact both the return on capital (profit) and return of capital (depreciation). Profit and depreciation form two of the building blocks in the price setting process specified in the RDWR.

Geoff Brown & Associates Ltd (GBA) has been engaged by the ERC to review the capital expenditure forecasts of the utilities that will enter PBR at the third entry point. These are:

- Cabanatuan Electric Corporation (CELCOR);
- Davao Light and Power Company (DLPC);
- Ibaan Electric and Engineering Corporation (IEEC);
- La Union Electric Company (LUECO);
- Tarlac Electric Incorporated (TEI); and
- Visayan Electric Company (VECO).

In accordance with clause 4.12.4 of the RDWR, the objective of the review is to determine whether each capital expenditure forecast is:

- based upon the best available prices obtainable from international markets;
- reasonably efficient from a design and implementation point of view;

1 *Rules for Setting Distribution Wheeling Rates for Privately Owned Distribution Utilities Entering Performance Based Regulation (Third Entry Point)*, Energy Regulatory Commission, December 8 2008.
2 No first regulatory period applied to the six utilities entering PBR at the third entry point.
3 *Regulatory Reset for the July 2010 to June 2014 Regulatory Period for Privately Owned Distribution Utilities subject to Performance Based Regulation, Position Paper*, Energy Regulatory Commission, 8 December 2008.

- likely to support the forecast growth in connections, co-incident peak demand and energy delivered; and,

- sufficient to allow the relevant utility to achieve or exceed the applicable target levels of performance.

This report presents GBA's review of the capital expenditure forecast of DLPC. The forecast was submitted to the ERC as part of DLPC's revenue and performance incentive scheme application (revenue application), on June 16, 2009.

In undertaking this review we have relied on the accuracy of the information provided to the ERC by DLPC. While during the clarificatory meeting process we queried information that appeared to be incomplete, inconsistent or inaccurate, we did not undertake an audit or attempt to verify the information on which we relied. We therefore cannot be held responsible for any conclusions or recommendations based on misleading or inaccurate information provided to us.

2. NETWORK OVERVIEW

2.1 NETWORK DESCRIPTION

DLPC is the third largest electricity distribution utility in the Philippines with approximately 256,000 customers and a peak demand of 244 MW. Its franchise area includes the cities of Davao and the municipalities of Panabo, Carmen, Dujali and Santo Tomas.

Currently, DLPC takes supply at 138 kV from the National Grid Corporation of the Philippines' (NGCP) 138 kV switching station at Bunawan and its 138/69 substation at New Loon[4]. It also takes supply at 69 kV from New Loon. The 138 kV supply points feed two (2) DLPC owned 138/69 kV substations, ERA and Don Ramon[5].

The Don Ramon substation has two 138/69/13.2 kV transformers, each rated at 50 MVA. The 13.2 kV tertiary bus is used as a local service supply and also as a connection point for a small generator, which is used as a standby supply for an emergency control room. There is also an intertie to a feeder on DLPC's Bunawan 69/13.8 kV zone substation.

The ERA substation has a single 138/69/13.8 kV transformer rated at 150/150/45 MVA. The 45 MVA 13.8 kV tertiary winding provides an interconnection to the 13.8 kV bus at the adjacent Bajada power station, which serves both as an injection point for some of the power station generators, and as a supply point for four 13.8 kV distribution feeders.

DLPC's 69 kV network supplies a total of 21 zone substations containing transformers of varying ratings but with a total capacity of 472 MVA. These zone substations in turn supply a distribution network that is used to distribute electricity to almost 15,500 distribution transformers located throughout the franchise area. The distribution transformers are used to convert the electricity to the low voltage that is used to supply the majority of DLPC customers.

The 69 kV network is divided into three sectors that, for the purposes of this report, are referred to as northern, central and southern.

- The northern sector supplies the far northern part of the franchise area and feeds five (5) 69/13.8 kV zone substations with a total transformer capacity of 85 MVA. It is supplied from both the New Loon and Don Ramon substations and there is also a 69 kV interconnection to NGCP's Tagum substation to the north of the franchise area.

- The central sector supplies the area immediately to the north of the Davao central business district (CBD) and feeds four (4) zone substations with a total capacity of 119 MVA as well as the Holcim cement plant. It can be supplied directly from the New Loon, ERA and Don Ramon substations. Power Barge No 4 also injects power into this sector.

- The southern sector supplies the Davao CBD and areas south and feeds eleven (11) substations (including Bajada) with a total capacity of 258 MVA. This sector is supplied by injection points at the Bajada/ERA complex and the New Loon substation. The southern part of this sector is also supplied via a tapping point on the NGCP's 69 kV Digos line.

[4] The substation is known by NGCP as Davao. It is referred to as New Loon in this report to avoid confusion.

[5] At the clarificatory meeting we got the impression that the full 138 kV Don Ramon substation switchyard was owned by DLPC. However the SKM valuation report states that this switchyard is still owned by NGCP, although DLPC is in negotiations to purchase and expects to conclude these negotiations during 2009. We have not had the opportunity to resolve this apparent inconsistency, but ownership of this asset does not impact DLPC's CAPEX plans. We note that the single line diagram shows a metering point within the Bunawan switching station and that there is no provision in the CAPEX forecast for the purchase of this asset.

There is also an isolated 10 MVA zone substation at Calinan, north-west of New Loon, which is supplied by a 69 kV spur line

While the above accurately describes the essence of the DLPC network the following features are of note.

- DLPC owns the Bajada power plant which we understand is located on the same site as the ERA substation. This power plant comprises 12 diesel fuelled generators with a total available capacity of 52.9 MW. Five (5) generators, with a total available capacity of 17 MW, inject into the network at 13.8 kV; further, six (6) generators with an aggregate available capacity of 32.8 MW inject at 69 kV. The final generator, with an available capacity of 3.1 MW, is connected to the tertiary winding of the Bajada substation transformer and can thus inject into the network at either voltage. However the Bajada power plant is not included in DLPC's RAB and does not form part of this review.

- National Power Corporation's Power Barge 104, with a name plate rating of 32 MW, injects into the central sector at 69 kV.

- DLPC has one (1) customer directly connected at 69 kV, Holcim Cement, with a maximum demand of about 24 MW.

2.2 CURRENT AND FORECAST DEMAND

Growth in peak demand is a key driver of capital expenditure and the forecast growth in demand therefore underpins this review. If, for example, the ERC considers that the peak demand forecast in the revenue application is high, then some of the projects forecast towards the end of the second regulatory period will not be required until after the start of the third regulatory period. DLPC's revenue application forecast the network after diversity peak demand to grow from 248.1 MW in CY 2008 to 313.7 MW in RY 2014, an increase of 65.6 MW, representing an average growth rate of approximately 4%. This was high compared to other utility forecasts, indicating that additional scrutiny was required as part of this review.

DLPC's historical network after diversity peak demand is shown in Table 2.1 and its corresponding forecast peak demand is shown in Table 2.2[6]. A comparison of historical and forecast demands is shown in Figure 2.1.

Table 2.1: Historical Peak Demand (MW)

	CY 2005	CY 2006	CY 2007	CY 2008
Peak demand	230.1	237.8	245.1	248.1
Growth rate		3.3%	3.1%	1.2%

Source: Revenue application Schedule H2

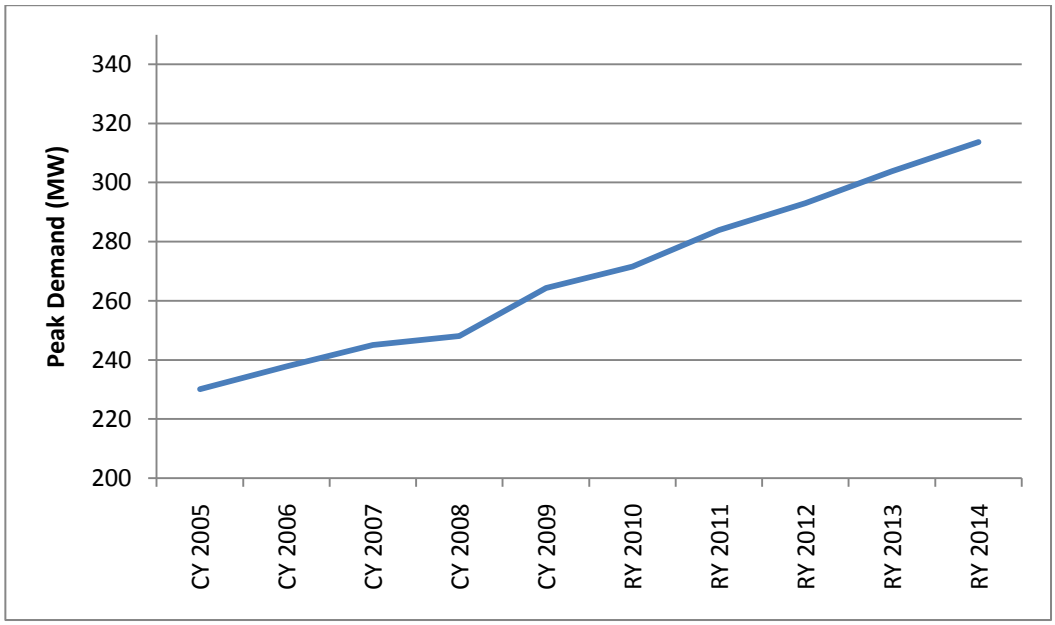
Table 2.2: Forecast Peak Demand (MW)

	CY 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Peak demand	264.3	271.6	283.9	293.0	303.8	313.7
Growth rate	6.5%	2.8%	4.5%	3.2%	3.7%	3.3%

Source: Revenue application Schedule H2

[6] Source: Revenue application, Schedules H2.1.1 and H2.1.2.

Figure 2.1: Comparison of Historical and Forecast Peak Demands



The analysis indicates that while the actual average annual growth rate over the three year period CY 2005-08 was under 2.6% the forecast growth rate over the period CY 2008-RY 2014 is 4%. DLPC has not provided a satisfactory explanation for the use of higher growth rates than experienced in the recent past. We contrasted this with the growth rates in the VECO application which showed an actual growth rate of 4.5% over the four year period CY 2004-08 and a forecast growth rate of 2.8%.

In order to assess whether the high forecast growth rate in DLPC's revenue application was reasonable, we researched historical growth rates over a longer period using data from the Department of Energy (DOE) web site. While data specific to VECO and DLPC was not available, the web site did provide peak demands on Mindanao and Cebu dating back to 1995. We think this data will be a reasonable indication for both DLPC and VECO, since they form a very significant portion of their respective grid loads[7]. The average annual growth rates on each grid are shown in Table 2.3.

Table 2.3: Average Annual Growth Rates

	Cebu Grid	Mindanao Grid
1995-2008	6.1%	3.4%
1999-2008	6.0%	3.3%
2004-2008	4.4%	1.3%

Table 2.3 shows that, while growth rates since 2004 have slowed substantially probably as a result of higher power prices resulting from the introduction of EPIRA, growth in the Mindanao grid has been consistently lower than in Cebu. The table indicates that over the period 2004-08 the DLPC growth rate was twice that of the growth on the Mindanao grid but provides no basis for forecasting a growth rate of the order of 4%. Indeed our view is that the growth rates experienced in the Philippines in the 1990s and early 2000s are unlikely to be repeated anywhere in the Philippines over the next 5 years because of (i) continuing high electricity prices (ii) the impact of the current recession and the fact that economists seem to generally agree that recovery will be unusually slow and (iii) the impact of climate change and the consequent moves worldwide to increase energy efficiency and reduce carbon emissions.

[7] In 2008, VECO's maximum demand represented 62% of the Cebu peak demand while DLPC's maximum demand was 21% of the Mindanao peak demand.

On this basis we think it would be more reasonable to assume a forecast growth rate of 2.6%, consistent with the actual growth rate experienced by DLPC since 2005. Hence the peak electricity demand that we have assumed as the basis for this review of forecast CAPEX is shown in Table 2.4.

The peak demands that we have assumed as the basis for this review are shown in Table 2.4.

Table 2.4: Assumed After Diversity Network Peak Demands

	2009	2010	2011	2012	2013	2014
MW	254.6	261.2	268.0	274.9	282.1	289.4
MVA[1]	267.9	274.9	282.1	289.4	296.9	304.6

Note 1: Assuming a power factor of 0.95.

2.3 NETWORK UTILIZATION

The extent to which the existing network is utilized is also relevant to the required capital expenditure since if the network is lightly utilized then the proposed capital expenditure can be deferred until demand growth has used up existing spare capacity.

A network that is heavily utilized will be unreliable since unplanned network faults will generally result in customers being left without supply until the fault is repaired. On the other hand networks that are lightly utilized are economically inefficient since they include excess assets that must be paid for but which are not delivering benefits to customers. Hence determining the appropriate level of network utilization requires reliability to be balanced against economic efficiency. As a first step in this review, we have estimated the network utilization of power transformers and 13.8 kV distribution feeder capacity in order to determine the extent to which spare capacity in the existing network can be used to accommodate the forecast growth in demand. We did not estimate the utilization of the 69 kV subtransmission network as the revenue application did not include any significant projects with the objective of increasing this capacity.

2.3.1 Utilization of Power Transformers

The 69/13.8 kV power transformers currently on the DLPC network are shown in Table 2.5.

Table 2.5: Existing Power Transformer Capacity

Substation	Transformers	Total Capacity (MVA)
Calinan	1 x 10 MVA	10
Toril	1 x 10/12/14 MVA	14
Dumoy	1 x 20/26/33 MVA	33
Puan	1 x 15 MVA	15
Bangkal	1 x 12 MVA	12
Matina	1 x 15/20/25 MVA	25
Ecoland	1 x 20/26/33 MVA	33
Sta. Ana	1 x 12 MVA	12
P. Reyes	1 x 20/26/33 MVA	33
Gaisano	1 x 20/26/33 MVA	33
Victoria	1 x 15 MVA	15
Bajada	1 x 20/26/33 MVA	33
R. Castillo	1 x 20/26/33 MVA	33
Pampanga	1 x 20 MVA	20
Panacan	1 x 20/26/33 MVA	33
Tubungco	1 x 20/26/33 MVA	33
Bunawan	1 x 10 MVA	10
Panabo	1 x 10 MVA	10
San Vicente – A	1 x 10 MVA	10
San Vicente – B	1 x 20 MVA	20
Tadeco	1 x 20 MVA	20
Sto. Tomas	1 x 15 MVA	15
Total		**472**

Source: SKM Valuation Report and DLPC.

As shown in Table 2.5 above, the forecast peak demand at the end of the second regulatory period is 289.4 MW. However this includes the 24 MW Holcim Philippines load that is supplied at 69 kV and therefore does not use this transformer capacity.

For the purposes of this analysis we have therefore assumed that the maximum 13.8 kV coincident demand in 2008 was 236 MVA, after discounting the 69 kV load component and assuming a power factor of 0.95. We have forecast this to increase to 279 MVA at the end of the second regulatory period. Hence, if no additional transformer capacity is added the power transformer utilization will increase from a current 50% to approximately 59% at the end of the second regulatory period.

In its revenue application for entering PBR at the first entry point, MERALCO used 70% power transformer utilization as its planning criterion for the maximum acceptable transformer utilization and this was accepted as reasonable by both PB Associates and the ERC[8]. We think it reasonable to use a planning criterion based on a global analysis of transformer utilization for networks where there is a high level of normally open interconnection between distribution feeders from neighboring substations. For such networks it is possible to optimize loading of the transformer population by reconfiguring the distribution network. Hence, when a power transformer becomes heavily loaded, the utility should first look to reduce the loading on the transformer by transferring excess load to other less heavily loaded transformers. We note that in its revenue application, DLPC has provided no evidence that it does this.

[8] *Review of Forecast Expenditure, Manila Electric Company;* PB Associates, February 22 2007, Section 2.3.1, p4.

We also believe that a MERALCO's 70% maximum power transformer utilization criterion is appropriate. The 30% unused capacity makes provision for diversity[9], and for the unplanned loss of a single transformer at times of peak load[10].

Assuming a 279 MVA peak load, a total power transformer capacity of around 399 MVA is required by the end of the second regulatory period if transformer utilization is to be kept below 70%. We note this is only 85% of existing installed capacity.

We note that DLPC also has a mobile transformer available for emergency use, but we have included this in our analysis, as it takes time to install in an emergency. The availability of this transformer mitigates the risk of a major transformer failure resulting in an extended outage and also provides even more comfort should load increase at a significantly higher rate than assumed for this review.

2.3.2 Utilization of the Distribution Network

The analysis of transformer utilization in Section 2.3.1 presupposes that there is sufficient capacity in the distribution network to allow the network to be reconfigured and load to be transferred from one power transformer to another. To confirm this, we have measured the total capacity of the distribution network (at the connection point of each feeder) and compared this with the required level of load transfer.

The SKM Valuation Report states that DLPC's 13.8 kV feeder backbone lines use 336.4 MCM aluminum core steel reinforced conductor (ACSR)[11], which has a thermal capacity of 13 MVA. There are a total of 85 secondary distribution feeders on the DLPC network giving a total distribution capacity of 1,105 MVA if all distribution feeders were fully loaded. Hence, assuming no major distribution network augmentations, the forecast utilization of the distribution network at the end of the second regulatory period will be under 25%. This is low by international standards and confirms that high distribution network utilization is not a constraint that would prevent the loading of power transformers above current levels.

[9] A diversity provision is needed because the individual transformer peak loads will occur at different times.

[10] Under Table 5.1 of the Position Paper, a level of security of the subtransmission system of 'n-1' is permitted. This means that the utility should be able, after network reconfiguration, to supply all customers using existing assets following the loss of supply of a single power transformer at peak load.

[11] Page 54.

3. OVERVIEW OF HISTORICAL AND FORECAST EXPENDITURE

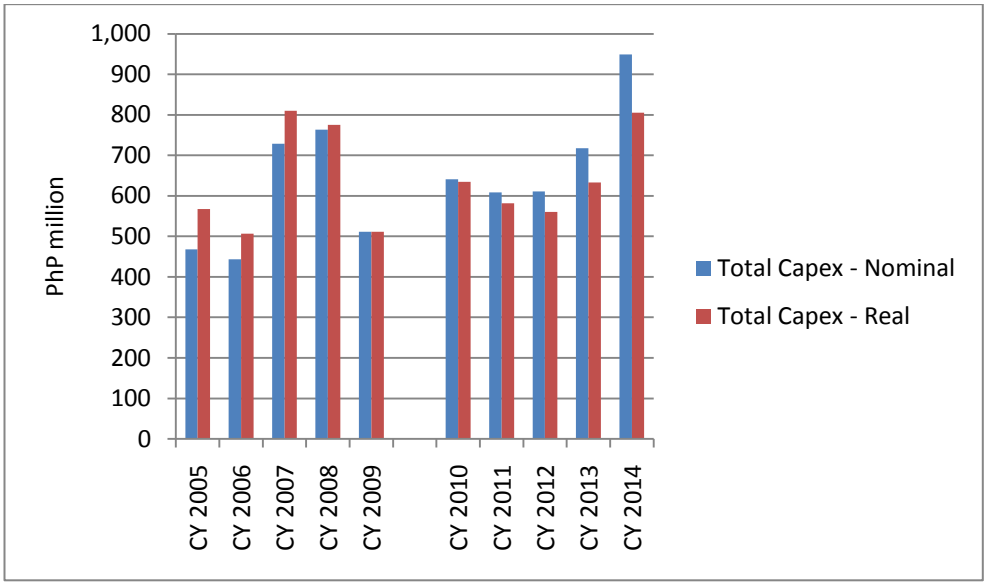
DLPC's historical and forecast total CAPEX, as presented in its revenue application, is shown in Table 3.1 below.

Table 3.1: Total Historical and Forecast CAPEX (PhP Million)

	Historical (Calendar Year)					Forecast (Regulatory Year)				
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
PhP nominal	468.23	443.24	728.82	762.99	511.71	640.52	608.47	610.67	717.25	949.12
PhP real	567.47	506.42	810.17	775.25	511.71	634.52	581.82	560.40	632.88	805.26

This historical and forecast CAPEX is shown graphically in Figure 3.1 below.

Figure 3.1: Total Historical and Forecast CAPEX (PhP Million)



An examination of the information above indicates that the base year for conversion from real to nominal is CY 2009. In that year, real and nominal expenditures are identical. For prior years nominal expenditure is less than the same expenditure expressed in real terms while in subsequent years the reverse applies. This is to be expected in situations where the real value of the peso depreciates over time. In this report all expenditures are expressed as PhP real, 2009 unless otherwise stated in order to remove the impact of the time value of money from our analysis.

For DLPC and all third entry point utilities, the regulatory year starts on 1 July and finishes on 30 June. RY 2010 denotes the regulatory year ending 30 June 2010. Hence there is a six month overlap between CY 2009 and RY 2010 and expenditure budgeted to occur during this overlap period (1 July 2009 – 31 December 2009) is shown twice in the above forecast. This is a consequence of the ERC's transition from calendar years to regulatory years for regulatory forecasting and rate setting purposes.

It can also be seen that, in real terms, budgeted and forecast CAPEX is particularly high in RY 2014 due primarily to the cost of the PhP247.5 Million Magtuod switching station, due for commissioning in June 2014.

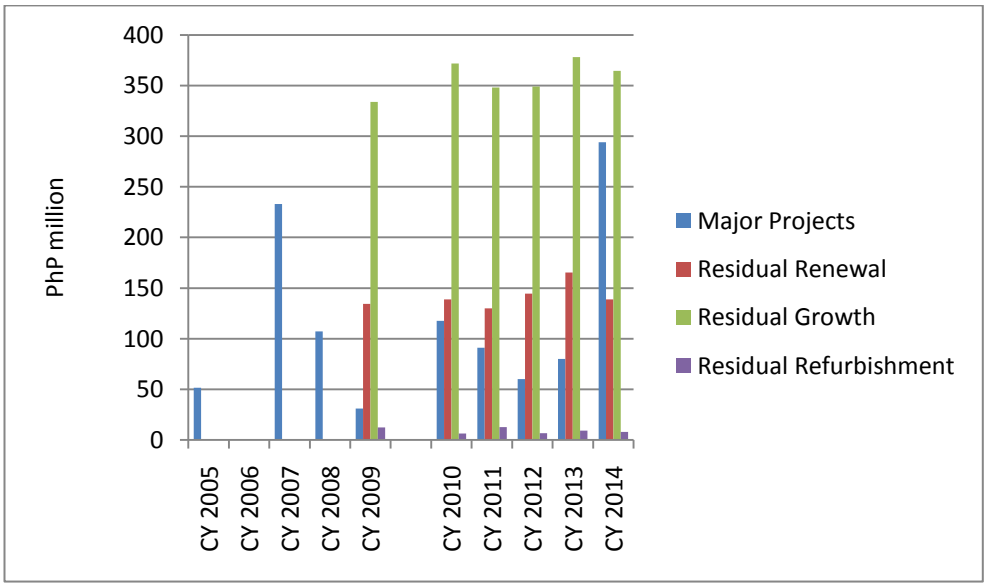
In Table 3.2 and Figure 3.2 below, DLPC's historical and forecast expenditure is broken down into the ERC major capital expenditure categories. While DLPC has provided its historical major project expenditure, it was unable to provide a breakdown of its residual

expenditure over the historical reporting years CY 2005-08 and historical residual expenditure is not shown.

Table 3.2: Breakdown of Historical and Forecast Expenditure (PhP Million, real)

	Calendar Year					Regulatory Year				
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Major Projects	51.71		232.95	107.05	31.10	117.47	91.05	60.06	80.06	294.10
Renewal					134.25	138.94	129.80	144.48	165.38	138.69
Growth					333.95	371.81	348.14	349.12	378.08	364.58
Refurbishment					12.41	6.29	12.84	6.73	9.36	7.89

Figure 3.2: Breakdown of Historical and Forecast Expenditure (PhP Million, real)



It can be seen from Figure 3.2 that DLPC's forecast CAPEX is largely driven by the residual growth expenditure and by the major project CAPEX on RY 2014. Major project CAPEX is discussed in Section 4 and residual CAPEX is discussed in Section 5 of this report.

4. MAJOR PROJECT EXPENDITURE

4.1 ACQUISITION OF DIGOS SUBTRANSMISSION LINE

DLPC's forecast CAPEX includes a provision of PhP30.00 Million for the purchase of the portion of NGCP's Digos line within its franchise area in accordance with the provisions of Section 8 of EPIRA. The major project information summary in the revenue application indicates that the transaction is expected to occur in June 2010.

NGCP's 69 kV Digos line runs between its New Loon and Matanao substations. It is a relatively new line that was energized in 1997. There is a tapping and metering point at Bato where DLPC takes supply to feed its Toril, Dumoy and Puan substations. Outside the DLPC franchise area, the line supplies San Miguel Corporation (which is understood to be a directly connected NGCP load) and DASURECO's Astorca substation. The line is normally operated as two radial circuits, energized from each end, with a normally open point at Astorca[12].

DLPC wants to purchase the section of this line within its franchise area. ERC approval for this transaction to proceed was given on July 11 2007[13]. However on August 23 2007, DASURECO filed its opposition to the sale going ahead and this matter has still to be resolved by the ERC. In its revenue application DLPC stated that it expected ERC to confirm its earlier decision and allow the sale to proceed.

In the major project summary sheet submitted with its revenue application DLPC stated:

> *This line is intended to supply DLPC's Toril substation, Dumoy substation and Puan Substations. This will act as a back-up line for Davao-Davao1 69 kV line in the event of failure. Acquisition of TransCo's subtransmission assets within its franchise area is in compliance with EPIRA where TransCo is mandated to divest its subtransmission assets to qualified distribution utilities.*
>
> *Without this line, Toril, Dumoy and Puan substations will be loaded to Davao-Davao1 69 kV line and will result to a much higher line losses on DLPC system. Davao-Digos 69 kV also acts as a back-up line if Davao-Davao1 69 kV line fails. In case of NGCP's shutdown Davao-Digos 69 kV line carries [the] majority of Davao-Davao1 69 kV line loads.*

The implication is that, if the sale does not proceed, then DLPC will need to relinquish its point of connection to the NGCP network at the Bato metering point. We see no basis for this. It has been argued that Section 5.5.1.2 of the Philippines Grid Code requires that all connections to the NGCP network must be controlled by a circuit breaker at the point of connection and that "tee" connections to an NGCP are no longer permitted. However we understand that this applies only to new connections and connections that were in existence at the time the Grid Code became effective are not required to be upgraded.

We have also reviewed the ERC decision on the case and note that Section C of the decision states that:

> *The documents submitted by TransCo, such as the single line diagram of the subject transmission assets, showed that DLPC is the only distribution utility directly connected thereto.*

We also noted that the agreed purchase price, based on a sound valuation undertaken by Transco and agreed to by was PhP15.29 Million.

[12] This is because NGCP will not allow 69 kV circuits to operate in parallel with its 138 kV network. This is to prevent 69 kV circuits becoming overloaded in the event of a fault on the 138 kV system.

[13] ERC Case No 2006-125MC.

Section 8 of EPIRA requires subtransmission assets to be sold to the qualified distribution utility or utilities connected to the assets[14]. It further provides that:

> *The takeover by a distribution utility of any subtransmission asset shall not cause a diminution of service and quality to the end-users. Where there are two or more connected distribution utilities, [a] consortium or juridical entity shall be formed by and composed of all of them and thereafter shall be granted a franchise to operate the subtransmission asset by the ERC.*

The ERC has issued guidelines as to what constitutes a subtransmission asset for the purposes of applying Section 8 of EPIRA.

> *Radial lines, power transformers, related protection equipment, control systems and other assets held by TRANSCO or its buyer or concessionaire which directly connect an end-user or group of end-users to a grid and are exclusively dedicated to the service of that end-user or group of end-users shall be classified as subtransmission assets.*

We do not consider the Digos line to be a radial line as it interconnects two NGCP substations. The fact that it is normally operated as two radial circuits, in that it is energized from either end with a normally open point somewhere in the middle, is an operational issue that does not change the essential nature of the asset. We note that the line is operated this way only to meet NGCP requirements and that the location of the normally open point can be changed.

Further we consider that, in addition to DLPC, both DASURECO and San Miguel are directly connected to the section of line covered by the purchase agreement. We suggest the test for direct connect be whether or not, if the asset was not made available by its owner, the user would remain connected to the network with the same level of security. In this case both San Miguel and DASURECO have an 'n-1' level of security with the asset in service, but this would be reduced to an 'n' level of security should DLPC buy the asset and then not make it available to them.

If it is accepted that DASURECO and DLPC are directly connected parties, then Section 8 of EPIRA provides that they form a juridical entity which is then granted an operating franchise by ERC. It appears that, if a juridical entity cannot be formed, then DLPC may be precluded from buying a section of the asset on its own account, not only because such a sale would be contrary to the EPIRA requirement, specifying eligible buyers but also because such a sale would potentially *cause a diminution of service and quality to the end-users.*

There appear to be good reasons for this EPIRA requirement. If DLPC was to buy that portion of the line within its own franchise area, it could then unilaterally assert its ownership rights and not make supply available to either DASURECO or San Miguel and neither party would have any recourse. This could occur, for example, if DLPC wanted the capacity currently used by either DASURECO or San Miguel, to supply its own customers.

We also note that the provision for the purchase of the asset in the revenue application CAPEX forecast is PhP30.00 Million whereas, as noted above, the agreed purchase price approved by the ERC in its July 2007 decision was only PhP15.29 Million. We have not seen any explanation for this discrepancy.

Given the above price discrepancy and the fact that the ERC has still to make a decision on DASURECO's opposition to the sale proceeding, we recommend that no provision for the purchase of the Digos line be included in DLPC's approved CAPEX forecast. Should this transaction proceed before the end of the second regulatory period, we suggest the

[14] Guidelines to the Sale and Transfer of the TransCo's Subtransmission Assets and the Franchising of Qualified Consortiums.

cost should be recovered through a retrospective adjustment to DLPC's approved CAPEX for the third regulatory period. The impact of this adjustment on DLPC's CAPEX forecast is shown in Table 4.1 below.

The impact of this recommendation on DLPC's forecast CAPEX is shown in Table 4.1 below.

Table 4.1: Adjustments to Cost of Digos Line Purchase (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast		30.00				
Adjustment for deletion purchase cost		(30.00)				

4.2 BAJADA B SUBSTATION REHABILITATION

DLPC's forecast CAPEX includes a provision of PhP31.10 Million for the replacement of a 13.8 kV switchboard at Bajada power station. The expected commissioning date is December 2009 and, unlike most major projects, the work is classified as renewal rather than growth.

Three circuit breakers are used to connect Bajada power station generators to the network and one is used to supply a primary feeder that connects the Bajada power station directly to the Gaisano substation, thereby providing support to the central business district. The fifth circuit breaker appears to supply a secondary distribution feeder.

DLPC has provided little information on the age or condition of the switchgear being replaced but has stated that they use oil interrupters. This would indicate they are relatively old as this technology has now been superseded by SF_6 and vacuum interrupters. The replacement circuit breakers will have vacuum interrupters.

While we would have liked DLPC to have provided more information on the age and condition of the existing assets, we nevertheless recommend that the project proceed. Three (3) of the circuit breakers are generator breakers and one supplies a primary feeder, which we consider important to the operation and reliability of the network.

We did consider whether the three (3) generator circuit breakers should be considered part of the power station rather than a regulated distribution asset[15] but noted the comment in the SKM Valuation Report that:

> *…based on SKM's interpretation of the Guidelines, all assets downstream of the disconnectors / circuit breakers [that connect the generators to the power station 13.8 kV bus] should not be included in DLPC's distribution network assets.*

We take this to mean that the generator circuit breakers are connected in the RAB.

4.3 CUSTOMER CARE & BILLING PROJECT

In its revenue application, DLPC has included forecast CAPEX of PhP56.37 Million to cover its share of a new Oracle customer care and billing system that Aboitiz Power Company (APC) wants to install for use by all its distribution utilities. It anticipates the system will be commissioned in RY 2010.

The revenue application included a complete description of the system to be installed and a copy of the proposal from Oracle Consulting Services to provide the system. The

[15] If the assets had been a part of the power station rather than a regulated distribution services asset, we would have concluded that their replacement costs should not form part of DLPC's CAPEX forecast.

package offered is an integrated software package designed to handle every aspect of utility customer information including service connection, meter reads, rating, billing, and more and is intended to be configurable to different regulatory requirements and rating systems. Hence, it should be readily adaptable to changes in the industry or regulatory environment.

The system proposed is a "state of the art" solution that would be purchased by APC and would serve as a centralized billing and customer information system for use by all APC utilities. We think this approach is efficient – on its own, the cost would be excessive for any single utility. However, the proposal will standardize the approach to customer management across all APC utilities and will allow all access to world class utility software. We believe that APC has the expertise to successfully implement and utilize such a system.

The estimated total implementation cost of the system is PhP142.31 Million, based on an implementation cost of PhP74.43 Million, as set out in the Oracle proposal. The additional costs include license and annual support costs[16]. There is also a total of PhP26.25 Million of costs internal to APC, including hardware costs, training and the provision of internal implementation support. We consider the total cost and the basis for allocating this cost between the various APC utilities to be reasonable.

We recommend that cost of the project be included in the approved CAPEX forecast.

4.4 NEW ADMINISTRATION BUILDING

In its revenue application, DLPC has included forecast CAPEX of PhP60.00 Million for a new administration building at its existing head office complex at P. Reyes. It anticipates the building will be ready for occupancy in RY 2011.

DLPC is planning to move the customer services area out of the bottom floor of its main administration building to leased premises in the SM Davao City mall. A similar move by VECO in Cebu has been very successful. It is planned that back office services will be consolidated into a new administration building to be constructed on the same site as the existing building.

The existing administration building comprises an original building constructed around 1935, an extension of a similar size constructed in 1965, and two (2) slightly smaller concrete annexes constructed in 1975 and 1989. The original 1935 building appears to comprise around 30% of the available floor area.

It appears that the two (2) earlier buildings were constructed using closely spaced wood columns and girders and the two (2) later extensions used concrete columns. DLPC argues that this kind of construction does not provide for the optimum utilization of space, especially for customer services because of the location of the columns. Further, the age and construction materials of the buildings make them likely fire hazards and less capable of withstanding seismic forces.

At the clarificatory meeting we indicated to DLPC that it had provided insufficient information on the condition of the existing building to justify the construction of a replacement and asked that it provide an independent engineering report.

The engineering report assessed the design of the building, based on assumptions regarding the properties of wood and steel used in construction and gravity and seismic loadings. It concluded that:

- *From the results of the design check of the existing Davao Light and Power office building, it could be said that the current sizes of the timber beams and columns are inadequate to resist gravity in combination with seismic loads;*

[16] APC has assumed that the one-off licence cost and the first year's annual support costs will be capitalized. Subsequent year's annual support costs will be treated as OPEX.

- *Also, the concrete columns on one side have a tendency of moving the centre of rigidity towards these columns. Because of this, the building might have excessive torsional movements due to this irregularity.*

- *The structure at its current state is serviceable for current gravity loads. However, the building might suffer extensive damage due to additional SLS seismic loading and possible collapse due to additional ULS seismic loading.*

- *Hence it is recommended to properly retrofit or replace the structure altogether. Please note that retrofit or new building options are not covered by this report.*

We have the following comments:

- We have visited the DLPC administration building for the clarificatory meeting and it appears in much better condition and provides more space than the office facilities of many smaller utilities entering PBR. The relocation of the customer services facility, which currently occupies about 40% of the available floor space, will leave adequate space to meet the requirements of the remaining functions. DLPC does not dispute this and its proposed new building is actually smaller than the one it will replace. It justifies the need for the new building on the basis of the design and condition of the existing one and we consider this the only criterion on which the need for a replacement should be assessed.

- The engineer's report did not assess the condition of the building, which we assume to be serviceable. In essence it concluded only that the building was adequate for normal loads but does not meet current seismic design codes.

- The engineer's report recommends retrofitting or replacement. Unfortunately the report does not indicate what the retrofitting option might involve so we have no way of comparing the retrofit option with DLPC's proposed replacement option. We comment that now would seem to be an appropriate time to implement any retrofit option, given that much of the existing space is being vacated.

- We note that at least 40% of the floor area is constructed from concrete and the majority of this is no more than 20 years old. There is no indication that this part of the building could not provide good service to DLPC for many years to come. We see no basis on which DLPC should ask its customers to fund the replacement of those sections of the building that are still in good condition.

- While the information provided by DLPC is limited, there may be justification for replacing the wooden sections of the existing structure. We note the comment on torsional loads in the engineer's report and that these appear to be caused by the construction of the building with materials of different properties. If this part of the building is to be replaced with a concrete structure it would be appropriate to do it immediately after the customer services section has vacated the ground floor.

- One possibility would be to replace the wooden part of the existing building with a completely new building, albeit smaller than the one currently proposed. However the concrete additions that would be retained are built as annexes to the perimeter of the original structure and on their own may not be completely functional. Hence, demolishing the existing wooden structure and rebuilding in its existing location, possibly on a slightly smaller footprint, may be a better option.

- DLPC has costed the proposed new building at PhP30,000 per m^2. Asian Appraisal has advised us this is high and that PhP25,000 per m^2 is a more reasonable provision.

We recommend that the provision for this project in the CAPEX forecast be reduced to PhP25.00 Million. This should be sufficient for DLPC to replace the wooden portions of the existing building with a new concrete structure with a size of up to 1000 m^2.

The impact of this adjustment is shown in Table 4.2 below.

Table 4.2: Adjustments to Cost of Administration Building (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast			60.00			
Adjustment for smaller structure.			(35.00)			

4.5 UPGRADE OF STA. ANA SUBSTATION

In its revenue application, DLPC has included forecast CAPEX of PhP31.05 Million to upgrade the Sta. Ana substation from 12 MVA to 33 MVA. It anticipates the project will be commissioned in December 2010. The project includes the installation of a larger transformer and a new five (5) circuit breaker gas insulated 13.8 kV switchboard.

In the major project information summary, DLPC states that this project will allow it to offload the heavily loaded Gaisano and Victoria Plaza substations that serve the central business district (CBD) area of Davao.

The relatively low power transformer and distribution network utilizations discussed in Sections 2.3.1 and 2.3.2 indicate that projects intended to further increase power transformer capacity are not required before the second regulatory period. There would appear to be scope for DLPC to rationalize its use of its existing capacity by reconfiguring the normally open points on its distribution network so that the loading of substations across the network better matched individual substation transformer capacities.

However, since the Sta. Ana substation serves the CBD we analyzed the substation loadings in and around the CBD. This analysis looked both at the substations serving the CBD area and at substations on the CBD fringe, which should be capable of absorbing some CBD load.

This analysis is shown in Table 4.3. Individual substation peak demands for CY 2008 are taken from Schedule H of the revenue application, converted to MVA assuming a power factor of 0.95, and then escalated to RY 2014 peak demands assuming the growth rates implied by the load forecast in Table 4.3

Table 4.3: Analysis of central Business District Transformer Loadings (MVA)

Substation	Capacity	2008 Peak Demand	2008 Utilization	2014 Peak Demand	2014 Utilization
Central Business District					
Bajada	33	15.9	48.2%	18.5	56.2%
Victoria	15	11.4	75.8%	13.3	88.4%
Sta. Ana	12	5.7	47.4%	6.6	55.2%
Gaisano	33	25.1	75.9%	29.2	88.5%
R Reyes	33	23.6	71.5%	27.5	83.3%
Total	**126**	**81.6**	**64.7%**	**95.1**	**75.5%**
Fringe					
R. Castillo	33	25.6	77.5%	29.8	90.4%
Ecoland	33	22.1	67.0%	25.8	78.1%

Table 4.3 indicates that the situation is acceptable for 2008 loads. Transformer loading is less than 65% and the spare transformer capacity is about 44 MVA, more than the 33 MVA capacity of the largest transformers. However, by 2014 the total utilization is 75.5% and the spare capacity reduced to less than 31 MVA.

In reality the situation in 2014 is manageable. The analysis in Table 4.3 takes no account of diversity and some load can be transferred to the fringe transformers. Notwithstanding this, given the importance of the CBD loads, the inherent uncertainties in load forecasting and the already high loading of the fringe transformers, we think some reinforcement of the substation capacity in the CBD area is justified, notwithstanding the low transformer utilization across the network.

We therefore recommend that the funding for the project be allowed, but that the project be deferred from RY 2011 to RY 2013. Our recommended adjustment is shown in Table 4.4.

Table 4.4: Adjustments to Cost of Sta. Ana Substation Upgrade (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast			31.05			
Adjustment for project deferral.			(31.05)		31.05	

4.6 NEW MAA SUBSTATION

In its revenue application, DLPC has included forecast CAPEX of PhP60.06 Million[17] to install a new 33 MVA substation at Maa. It anticipates the project will be commissioned in December 2011.

In its major project information summary, DLPC states that the substation will support the city south area, which is fast becoming a load centre for light industrial, big commercial and high-end residential power consumers. With the recent construction/development seen in the area, it believes that the existing capacity of its substations serving the area (Ecoland, Bajada and Matina) would no longer be sufficient to supply the power demand starting RY 2012.

Given the relatively low utilization of transformer capacity across the network we are unable to accept this argument. We think there is scope for a global rationalization of transformer utilization across the network by reconfiguring the normally open points within the distribution network so that transformer loadings better match their capacity. Such a rationalization would ensure that load in the more highly loaded parts of the network is transferred to less highly utilized assets and should be sufficient to reduce the loading in areas like the city south so that the situation is managed at least until the end of the second regulatory period.

We therefore recommend that the forecast CAPEX for this project not be approved. The impact of this recommendation is shown in Table 4.5

Table 4.5: Adjustments to Cost of Maa Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast				60.06		
Adjustment for project deletion.				(60.06)		

4.7 ADDITIONAL LOT AT MAA – MIDLAND

In its revenue application, DLPC has included forecast CAPEX of PhP44.35 Million to purchase new land at Maa. It anticipates the transaction will be completed in RY 2013.

The land adjoins DLPC's existing training facility and will be used for the development of a specialized linemen training area, as a pole stockyard and also for other materials storage. Asian Appraisal has confirmed that the purchase price is reasonable.

[17] This cost has been taken from the template rather than the major project information summary.

We recommend that the provision for this project in the CAPEX forecast be approved.

4.8 NEW MINTAL SUBSTATION

In its revenue application, DLPC has included forecast CAPEX of PhP35.71 Million to install a new 12 MVA substation at Mintal utilizing the power transformer to be removed from Sta. Ana. It anticipates the project will be commissioned in June 2013.

In its major project information summary, DLPC states that the substation will support the load in the south west area. This is an area that is not well served by existing substations with the nearest substation being Puan, which is about 17 km away.

Given the fact that this new substation would be located in a rural area, which is not well served by the existing distribution network we reviewed the information provided by DLPC in some detail. The area is currently serviced by a 13.8 kV line running between the Calinan and Puan / Bangkal substations. An additional line feeds into the area from the Bajada power plant via the 1.1 MW Talomo hydro plant. Even if Talomo is not generating, none of the substations that supply the area are particularly heavily loaded and we are satisfied that sufficient power injection capacity would be available to supply the area in an n-1 contingency situation

The other issue raised in the major project information summary is voltage regulation, which could be an issue due to the relatively long feeder lengths. DLPC has provided no quantitative information to indicate the severity of any issue. Our view is that the problem is unlikely to be critical given that we estimate the maximum load on each feeder to be below 3 MVA under normal operating conditions, which is much lower than the 13 MVA feeder rating. Further, our experience is that 17-20 km is not an excessive length for a 13.8 kV feeder supplying a rural area. On this basis we are satisfied that any voltage regulation issue can be managed at least until the end of the second regulatory period and probably longer.

We are also not satisfied that construction of a new substation would be the most cost effective way of addressing any voltage regulation issue. Installation of one or more voltage regulators, or reconductoring feeder sections that may be less than 336.4 MCM are potentially less costly alternatives and should be explored.

We therefore recommend that the forecast CAPEX for this project not be approved for the second regulatory period. The impact of this recommendation is shown in Table 4.6

Table 4.6: Adjustments to Cost of Mintal Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast					35.71	
Adjustment for project deletion.					(35.71)	

4.9 MAGTUOD 138 KV SWITCHING STATION

In its revenue application, DLPC has included forecast CAPEX of PhP247.50 Million to install a new 138 kV substation at Magtuod. It anticipates the project will be commissioned in June 2014.

DLPC's 138/69 kV ERA substation is supplied by a single radial 138 kV line fed from NGCP's New Loon substation. During the third regulatory period DLPC is proposing to construct a second incoming circuit to ERA and this switching station will allow this new line to be fed from NGCP's 138 kV Bunawan - New Loon circuit.

Given the forecast cost of this project, we believe a careful examination of its justification was necessary in order to evaluate whether the capital expenditure is required and whether the timing is appropriate. To this end, we invited DLPC to a second clarificatory

meeting, where it gave a presentation on the design of the project and why it was needed. The slides from this presentation form part of the records of this case.

Project Need

At the second clarificatory meeting, DLPC explained that it believed a second circuit supplying the ERA substation was needed for the following reasons:

- The existing circuit passes through a rural area and is considered a potential terrorist target. DLPC provided evidence of a number of instances where the electricity supply in Mindanao has been disrupted by terrorist activity in Mindanao, although none appear to have involved the radial line supplying ERA. Notwithstanding this, we accept that the electricity supply in Mindanao is at risk of disruption as a result of terrorist activity and that the existing line is a potential target.

- NGCP has a policy of not connecting loads at 138 kV through a single radial circuit. Only large loads are directly connected at 138 kV and a sudden loss of such a load can affect the dynamic performance of the network. When a network unexpectedly loses a significant proportion of its connected load generators speed up. If rapid corrective action is not taken (usually automatically though the operation of automatic protection and control systems), some generators may lose synchronism and extreme situations network collapse might occur.

  We accept this argument in principle but have no information on which to assess the seriousness of the problem in this instance. We comment, however, that the bulk of the generation on the Mindanao grid is hydro, which generally runs at low speeds and, for this reason, is tolerant of grid frequency excursions. DLPC confirmed at the clarificatory meeting that it had not received a formal request from NGCP to provide a second incoming circuit to the ERA substation.

- Should supply be lost to ERA, DLPC would be unable to restore supply to all customers before the fault was repaired (in other words the 'n-1' criterion was not met). DLPC provided an analysis was to support this argument. However the analysis assumed that the generation directly connected to the DLPC network (Bajada Power Plant or Power Barge 104) was not operational. We think this assumption is unwarranted and believe that DLPC can supply all loads without the ERA substation, given the forecast loads in RY 2014.

  In this regard, we note the most severe 'n-1' contingency would be a long term loss of the single ERC 138/69/13.8 kV ERA transformer and the information provided does not specifically discuss how DLPC would manage such an event (which would not be mitigated by a second incoming line). We can only assume that DLPC believes there is sufficient redundancy in the existing power to manage this situation through to the end of the second regulatory period in the unlikely event that such a situation arises. We agree with this assessment.

Project Design

The project, as currently planned, is a double bus arrangement with two circuit breakers per circuit, requiring the installation of ten circuit breakers. This is a higher standard design than NGCP routinely applies at its 138 kV substations and switching stations, which use only one and a half circuit breakers per circuit.

Our view is that a simplified design, involving a single bus and three circuit breakers at the point where the proposed new ERA line taps into the existing 138 kV Bunawan – New Loon line would give an adequate degree of reliability.

Other Issues

- The proposed project is actually a transmission project where NGCP's 138 kV Bunawan-New Loon line would be diverted into the new switching station. However, it appears that DLPC has included this project in its revenue application without any formal agreement from NGCP that the project should proceed as proposed. We believe that, if the project did proceed, the switching station would need to be operated as an integral part of the transmission system, which would require NGCP to have full operational control.

- The project is proposed for commissioning at the end of the second regulatory period, even though its benefits will not be realized until the second circuit to the ERA substation is commissioned. This is not planned until the third regulatory period. In our view, even if the asset was constructed as scheduled, it would not meet the requirements for inclusion in the RAB on completion, as its intended benefits could not be delivered at that point.

We therefore recommend that the project not be approved for completion before the end of the second regulatory period. We also do not think that DLPC should be submitting projects that impact the design or operation of the transmission grid without the explicit written support of NGCP.

The impact of this recommendation is shown in Table 4.7

Table 4.7: Adjustments to Cost of Magtuod Switching Station (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast						247.50
Adjustment for project deletion.						(247.50)

4.10 NEW BUHANGIN SUBSTATION

In its revenue application, DLPC has included forecast CAPEX of PhP46.60 Million to install a new 20 MVA substation at Buhangin using the transformer removed from Panacan substation. It anticipates the project will be commissioned in June 2014.

In its major project information summary, DLPC states that the substation will support the city north area, which is experiencing industrial commercial and residential growth. The new substation will enable the R. Castillo and Panacan substations to be offloaded.

Given the relatively low utilization of transformer capacity across the network we are unable to accept this argument. We think there is scope for a global rationalization of transformer utilization across the network by reconfiguring the normally open points within the distribution network so that transformer loadings better match the available capacity. Such a rationalization would ensure that load in higher loaded parts of the network is transferred to less highly loaded assets and should be sufficient to reduce the loading in areas like the city south so that the situation is managed at least until the end of the second regulatory period.

We also note that the proposed commissioning date is June 2014, at the very end of the second regulatory period. This is based on a load forecast that we believe to be high, as discussed in Section 2.2. Hence, even without rationalization of transformer loadings, we are satisfied that the timing of project could be deferred to the third regulatory period.

We therefore recommend that the forecast CAPEX for this project not be approved. The impact of this recommendation is shown in Table 4.8.

Table 4.8: Adjustments to Cost of Buhangin Substation (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast						46.60
Adjustment for project deletion.						(46.60)

4.11 SUMMARY OF MAJOR PROJECT EXPENDITURE

Table 4.9 below provides a breakdown of DLPC's forecast major project expenditure into individual projects. It can be seen that the costs as provided in the major project sheets reconcile with the template and no additional adjustment is required.

Table 4.9: Breakdown of Forecast Major Project Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Revenue Application Template	-	117.47	91.05	60.06	80.06	294.10
Revised Major Project Sheets						
Acquisition of Digos line		30.00				
Bajada B substation rehabilitation		31.10				
Customer care and billing software		56.37				
New administration building			60.00			
Sta. Ana substation upgrade			31.05			
New Maa substation				60.06[1]		
Acquisition of Maa lot					44.35	
New Mintal substation					35.71	
Magtuod switching station						247.50
New Buhangin substation						46.60
Total Major Projects	**-**	**117.47**	**91.05**	**60.06**	**80.06**	**294.10**

Note 1: Project cost taken from the template. There is a discrepancy between the template and the major project information summary.

The recommended adjustments for individual projects are summarized in Table 4.10 below.

Table 4.10: Summary of Individual Adjustments (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Deletion of Digos line acquisition	-	(30.00)				
Adjustment to cost of administration building			(35.00)			
Deferral of Sta. Ana substation upgrade			(31.05)		31.05	
Deletion of new Maa substation				(60.06)		
Deletion of new Mintal substation					(35.71)	
Deletion of Magtuod switching station						(247.50)
Deletion of new Buhangin substation						(46.60)
Total	**-**	**(30.00)**	**(66.05)**	**(60.06)**	**(4.66)**	**(294.10)**

Our recommended major project CAPEX for the second regulatory period is shown in Table 4.11 and a comparison between the DLPC forecast and our recommendation is shown in Figure 4.1.

Table 4.11: Summary of Recommended Major Project CAPEX Expenditure (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Revenue application template	-	117.47	91.05	60.06	80.06	294.10
Recommended adjustments	-	(30.00)	(66.05)	(60.06)	(4.66)	(294.10)
Recommended major project CAPEX	**-**	**87.47**	**25.00**	**-**	**75.40**	**-**

Figure 4.1: Comparison of DLPC Forecast and Recommended Major Project CAPEX

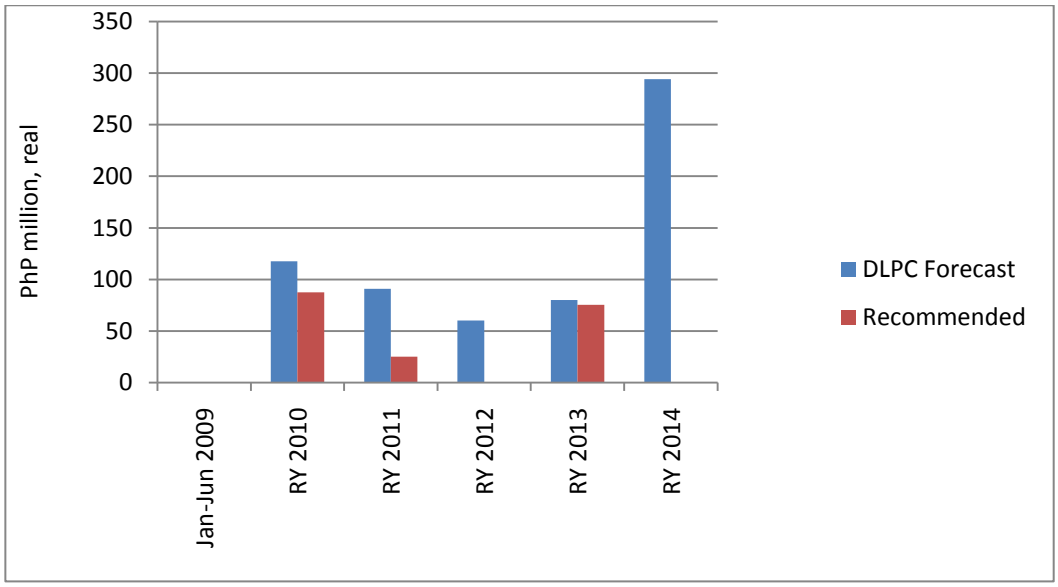


Table 4.12 breaks down the major project expenditure into the major expenditure drivers for OPEX modeling. The Bajada B substation rehabilitation project is classified as network replacement and the new administration building and the customer care and billing systems are classified as non network replacement. The Sta. Ana project is classified as network growth.

Table 4.12: Breakdown of Recommended CAPEX by OPEX Driver (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Network growth					31.05	
Network replacement		31.10				
Non-network growth					44.35	
Non-network replacement		56.37	25.00			
Total		**87.47**	**25.00**		**75.40**	

5. RESIDUAL CAPITAL EXPENDITURE

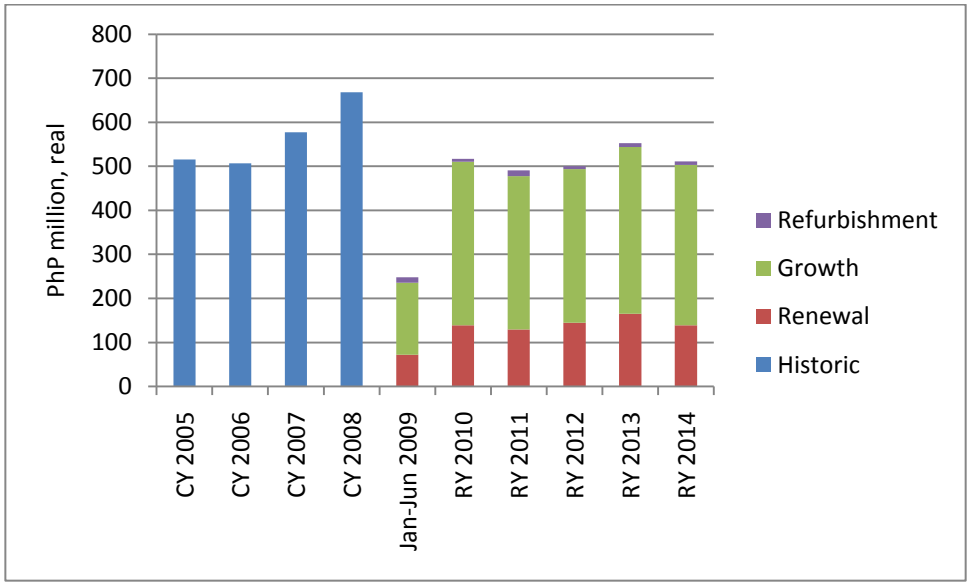
5.1 INTRODUCTION

DLPC's historical and forecast residual CAPEX, taken from its revenue application template, is shown in Table 5.1 and Figure 5.1.

Table 5.1: Historical and Forecast Residual CAPEX (PhP Million, real)

	CY 2005	CY 2006	CY 2007	CY 2008	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Renewal					72.28	138.94	129.80	144.48	165.38	138.69
Growth					163.14	371.81	348.14	349.12	378.08	364.58
Refurbishment					12.24	6.29	12.84	6.73	9.36	7.89
Total	**515.77**	**506.42**	**577.22**	**668.20**	**247.67**	**517.04**	**490.78**	**500.33**	**552.82**	**511.17**

Figure 5.1: Historical and Forecast Residual CAPEX (PhP Million, real)



It can be seen that DLPC was able to report its annual historical residual CAPEX but was not able to segregate it into the ERC's three (3) standard expenditure categories. Its forecast residual CAPEX is relatively constant throughout the forecast period and at a similar level to its historical spend, when measured in real peso. It is dominated by growth related expenditure but its renewal expenditure is still significant. We have not reviewed the refurbishment expenditure, which we consider not material to the forecast.

In undertaking this expenditure review we have considered the reasonableness of the more significant one off expenditures and individual line items. It has not been possible to compare forecast with historical expenditure on a line item basis since historical expenditures (except for the CY 2009 budget) have not been disaggregated into the ERC's primary expenditure categories. However we have assessed the reasonableness of the individual line items based on all the information available to us, including that in DLPC's revenue application and submissions following the clarificatory meetings. The results on the benchmarking exercise described in Section 5.2 below have also been taken into account.

This report generally considers the individual line items on an exception basis and does not individually discuss the line items that appear to be reasonable.

5.2 BENCHMARKING OF DLPC'S RESIDUAL CAPEX

Notwithstanding the fact that DLPC's residual CAPEX is comparable with its reported historical expenditure level; the magnitude of both historical and forecast CAPEX appears high when compared to the expenditures reported by the other utilities entering PBR at the third entry point. To confirm this, we undertook a benchmarking exercise where we compared DLPC's regulated distribution services residual CAPEX with the corresponding expenditures in the revenue applications of other utilities, when normalized against key expenditure drivers. We assumed the growth in peak demand to be a key driver of growth related residual CAPEX and the value of the regulated distribution services asset base, to be a key driver of renewal and refurbishment CAPEX. IEEC was not included in the analysis because of its very small size. The results of the benchmarking exercise are shown in Table 5.2.

Table 5.2: Benchmarking of Residual CAPEX Expenditure on Regulated Distribution Services

	Growth CAPEX RY2010-14	R & R[1] CAPEX RY2010-14	Load Increase 2009-14	ORC (December 08)[2]	ODRC (December 08)[2]	Growth CAPEX / MW	R & R[1] CAPEX / ORC	R & R[1] CAPEX / ODRC
	(PhP Million)	(PhP Million)	(MW)	(PhP Million)	(PhP Million)	(PhP Million)	-	-
CELCOR	102.63	57.44	4.50	921.88	656.16	22.81	0.062	0.088
DLPC	1,411.51	646.44	49.37	7,249.73	5,173.39	28.59	0.089	0.125
LUECO	46.60	13.50[3]	3.98	456.34	308.76	11.71	0.030	0.044
TEI	150.67	53.86	8.96	1,137.85	872.58	16.82	0.047	0.062
VECO	302.67	537.51	47.83	7,185.96	5,283.99	6.33	0.075	0.102

Note 1: R & R = renewal and refurbishment
Note 2: Source: SKM Valuation report
Note 3: After adjustment to remove value of stores and spares from reported expenditures.

It can be seen from Table 5.2 that DLPC's residual CAPEX is indeed high when compared to the other utilities. Its normalized growth related CAPEX is 25% higher than the next highest utility; the normalized renewal and refurbishment CAPEX indictors exceed the next highest utility by at least 19%. We recognize that a benchmarking exercise of this nature is imperfect as we have not rigorously checked that the expenditure allocation rules in the Position Paper have been uniformly applied. Nevertheless we are satisfied that any differences that such a check would identify would not be sufficient to fully explain the difference between DLPC and the other utilities.

5.3 RESIDUAL GROWTH CAPEX

5.3.1 Pampanga Substation Upgrade

DLPC is proposing to increase the capacity of the Pampanga substation from 20 MVA to 33 MVA. The forecast cost is PhP27.09 Million and commissioning is planned for December 2012. As the forecast cost of the project is less than the major project threshold of PhP30 Million, the cost was recorded as a residual growth project.

After the clarificatory meeting, DLPC provided a major project information summary of the project. This stated that the project aimed to deload R. Castillo and Panacan substations and provide additional capacity to meet load growth within the northern part of the city, particularly the areas of Lanang, Sasa and Panacan. It further stated that the substation was expected to improve supply reliability to customers in the area.

Given the very low transformer utilization on the DLPC network, as discussed in 2.3.1, we consider that this upgrade will not be required before the end of the second regulatory period. We also consider the forecast growth in peak demand on which the substation requirement was based is high as discussed in Section 2.2. A lower rate of growth will also defer the requirement for growth augmentations. We therefore recommend that

expenditure for the upgrade of Pampanga substation not be included in the CAPEX forecast.

The impact of these adjustments on the CAPEX forecast is shown in Table 5.3.

Table 5.3: Adjustments to Cost of Pampanga Substation Upgrade (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast					**27.09**	
Recommended Line Item Adjustments						
Structures and Improvements:					(0.22)	
Station Equipment:						
Power Transformers					(15.36)	
Switchgear					(4.54)	
Protective equipment					(3.35)	
Metering and control equipment					(0.05)	
Other station equipment					(3.57)	
Total recommended adjustment					**(27.09)**	

The major project information summary gave no information on the reason for the replacement of the switchgear but we suspect that DLPC intends to replace the 69 kV switchgear.

5.3.2 Station Equipment

DLPC's residual growth CAPEX forecast includes an average annual provision of PhP21.30 Million over the forecast period RY 2010-14 for additional substation equipment, excluding the cost of the Pampanga substation upgrade. No information has been provided on the reason for this expenditure. However we think that it most likely to provide mainly for the installation of additional 13.8 kV distribution feeders. We can think of no other reason for such substantial expenditure to increase the capacity of existing substations.

Our analysis in Section 2.3.2 indicates that, even without any additional distribution feeders, the utilization of the distribution network by the end of the second regulatory period would be only 25% and we consider this to be low by international standards. We therefore consider that a planned program for the installation of new distribution feeders at existing substations cannot be justified at this time. This is not to say that there will not be a requirement for a limited amount of augmentation at some existing substations to address specific localized problems.

We therefore recommend that residual growth CAPEX, after removing the provision for the Pampanga substation upgrade, be reduced by 80% of the amount forecast in the revenue application. The 80% reduction recognizes that while DLPC has provided no justification for any load related expenditure at existing substation some limited augmentation is likely to be required. Our recommended adjustment is shown in Table 5.4.

Table 5.4: Adjustments to Substation Equipment Residual Growth CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Switchgear						
DLPC Forecast		8.24	8.39	0.39	10.32	9.80
Recommended Adjustment		(6.59)	(6.71)	(0.31)	(8.26)	(7.84)
Protective equipment						
DLPC Forecast		1.62	2.47	1.98	2.47	2.73
Recommended Adjustment		(1.30)	(1.97)	(1.58)	(1.97)	(2.18)
Metering and control equipment						
DLPC Forecast		5.56	5.18	7.17	7.18	4.86
Recommended Adjustment		(4.45)	(4.15)	(5.74)	(5.75)	(3.89)
Other station equipment						
DLPC Forecast		7.81	6.88	0.50	7.69	5.27
Recommended Adjustment		(6.25)	(5.50)	(0.40)	(6.16)	(4.21)
Totals						
DLPC Forecast		23.22	22.92	10.04	27.67	22.65
Recommended Adjustment		**(18.58)**	**(18.33)**	**(8.03)**	**(22.14)**	**(18.12)**

5.3.3 Laboratory Equipment

DLPC has included expenditure of PhP5.00 Million for laboratory equipment in RY 2014 but no information has been provided on the purpose of the expenditure. Given the amount of expenditure involved, we are unable to recommend that it be allowed. In any case, any such expenditure in RY 2014 could easily be deferred until the third regulatory period.

Our recommended adjustment is shown in Table 5.5.

Table 5.5: Adjustments to Laboratory Equipment Residual Growth CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast		0.30		0.30		5.00
Recommended adjustment						(5.00)

5.3.4 New Customer Services Centre in SM Mall

DLPC has included a provision of PhP19.5 Million for a new customer services centre in the SM Davao City mall. This is recorded as residual growth CAPEX in RY 2010 under the line item *Structures and Improvements (non-network).*

The cost estimate is based on a fit out cost of PhP30,000 per m^2. We asked Asian Appraisal for advice on the reasonableness of this estimate, given that is was the same cost that DLPC used for a new building and were advised that the expected range of costs for such a fit out was PhP8,000 to PhP10,000 per m^2. We therefore recommend that DLPC's forecast be adjusted downwards to reflect a fit out cost of PhP9,000 per m^2.

Our recommended adjustment is shown in Table 5.6.

Table 5.6: Adjustments to Non Network Structures and Improvements residual Growth CAPEX (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast		24.09	2.17	5.16	0.93	3.62
Recommended adjustment for reduction in SM mall fit out costs		(13.65)				

5.3.5 Other Residual Growth CAPEX

There is a further category of residual CAPEX involving expenditure driven by incremental network growth and by growth in customer numbers. DLPC's forecast CAPEX on these line items is substantial.

DLPC's forecast growth in demand between 2008 (the last year for which confirmed actual data is available) and 2014 is shown in Tables 2.1 and 2.2. These tables show that, over this period, DLPC expects demand to grow from 248.1 MW to 313.7 MW, an increase of 65.6 MW. However our analysis in Section 2.2 indicates that we expect demand to grow by only 41.3 MW over the same period; in other words we expect the increase in peak demand to be approximately 37% less than that forecast by DLPC.

At the clarificatory meeting, DLPC further indicated that it expected the real cost of line transformers to increase over the forecast period and had allowed for these increases in its forecast. This was apparent from the annual line item costs which increased annually from RY 2010 so that by RY 2014 line transformer costs were 17% higher than at the start of the period. A similar pattern was evident for consumer metering and for customer service drops, but was not apparent for the other line items in the template.

To support this argument, DLPC provided an analysis that showed transformer costs had increased on average by 63% over the three year period CY 2005-08 due to increases in both materials and labor costs. DLPC considers that these increases will continue, albeit at a lower rate, over the forecast period. We do not agree. As a consequence of the recession copper prices reduced by more than 60% between June 2008 and February 2009. While much of this loss has been recovered, prices now show signs of stabilizing. The recession has brought with it increasing unemployment world-wide. While the world economy is now showing signs of recovery, economists predict this recovery to be slow and recovery in the labor market to lag other sectors. We therefore expect labor cost pressures through to the end of forecast period to be much lower than experienced over the historical period, which was a time of relatively strong economic growth.

The DLPC forecast for line transformers, metering and service lines has been prepared off a 2008 base when commodity prices were high. An assumption of no real increases in material and labor costs still allows these costs to rise in nominal terms at the same rate as inflation. On this basis we consider that an assumption of no real increases in materials or labor, as used in the OPEX forecasting model, is reasonable.

Table 5.7 shows our recommended adjustments to account for these factors for those line items where we consider growth expenditure is primarily driven by demand. We have reduced DLPC forecast cost for all line items by 37% to reflect our lower demand forecast. In addition, for line transformers we have adjusted out the real increase in prices by adjusting the DLPC forecast for the years RY 2011-14 down to the RY 2010 forecast level.

Table 5.7: Other Growth Related Residual CAPEX Adjustments – Regulated Distribution Services (PhP Million)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Poles, Towers and Fixtures – Distribution						
DLPC Forecast		54.71	66.78	67.99	55.49	62.15
Recommended Adjustment		(20.24)	(24.71)	(25.16)	(20.53)	(23.00)
Overhead Conductors and Devices – Distribution						
DLPC Forecast		35.30	47.38	48.92	43.79	43.08
Recommended Adjustment		(13.06)	(17.53)	(18.10)	(16.20)	(15.94)
Line Transformers – Distribution						
DLPC Forecast		95.09	99.60	105.07	108.15	110.79
Recommended Adjustment		(35.18)	(39.70)	(45.17)	(48.24)	(50.89)
Tools, Shop and Garage Equipment						
DLPC Forecast		10.71	6.78	9.50	9.20	7.30
Recommended Adjustment		(3.96)	(2.51)	(3.51)	(3.40)	(2.70)
Totals						
DLPC Forecast		195.80	220.54	231.48	216.63	223.32
Recommended Adjustment		**(72.45)**	**(84.44)**	**(91.94)**	**(88.38)**	**(92.52)**

Tables 5.8 and 5.9 shows our recommended adjustments for those line items categorized as regulated connection services or regulated retail services.

We have assumed that the primary driver of expenditure on overhead conductors and devices (Table 5.8) and consumer metering (Table 5.9) is customer numbers rather than demand growth. We have reviewed DLPC's forecast growth in customer numbers, as provided in the revenue application, and find that the forecast growth rate is consistent with the growth rate experienced over the historical period. This is what we would expect since customer numbers are less likely than growth to be impacted by the recession or by rising electricity prices. Hence the only adjustments to these two line items are to remove the affect of the apparent real price inflation. In both cases the adjustments have been calculated to ensure that the total expenditure in RY 2010 has been maintained (in real terms) throughout the remainder of the forecast period.

Table 5.8: Growth Related Residual CAPEX Adjustments – Regulated Connection Services (PhP Million)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Overhead Conductors and Devices (Customer)						
DLPC Forecast		3.41	3.51	3.60	3.69	3.78
Recommended Adjustment			(0.10)	(0.19)	(0.28)	(0.37)
Line Transformers (Customer)						
DLPC Forecast		10.48	10.98	11.58	11.92	12.21
Recommended Adjustment		(3.88)	(4.38)	(4.98)	(5.32)	(5.61)
Totals						
DLPC Forecast		13.89	14.49	15.18	15.61	16.00
Recommended Adjustment		**(3.88)**	**(4.48)**	**(5.17)**	**(5.60)**	**(5.98)**

Table 5.9: Other Growth Related Residual CAPEX Adjustments – Regulated Retail Services (PhP Million)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Meters, Instruments & Metering Transformers (Consumer Consumption Metering)						
DLPC Forecast		59.23	62.84	65.40	67.63	69.95
Recommended Adjustment			**(3.61)**	**(6.17)**	**(8.40)**	**(10.72)**

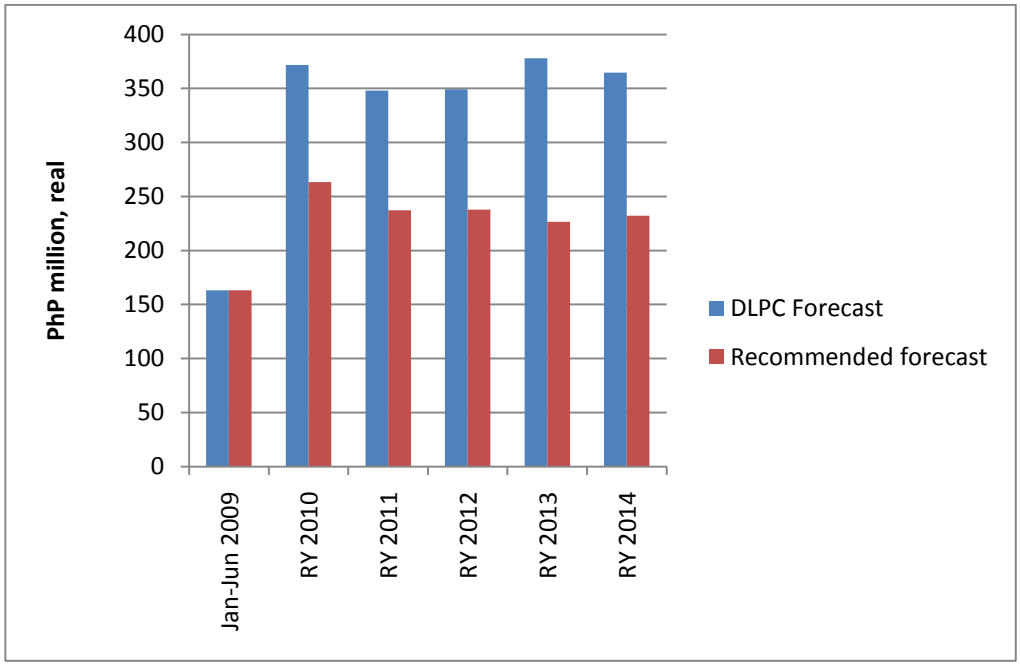
5.3.6 Summary

The recommended adjustments to DLPC's forecast residual growth CAPEX are summarized in Table 5.10 and the impact of these adjustments is shown in Figure 5.2.

Table 5.10: Adjustments to Residual Growth CAPEX Forecast (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast	163.14	371.81	348.14	349.12	378.08	364.58
Deletion of Pampanga substation upgrade					(27.09)	
Adjustments to expenditure on substation equipment		(18.58)	(18.33)	(8.03)	(22.14)	(18.12)
Adjustments to expenditure on laboratory equipment						(5.00)
Adjustments to expenditure on SM mall fit out		(13.65)				
Adjustments to expenditure on other regulated distribution services		(72.45)	(84.44)	(91.94)	(88.38)	(92.52)
Adjustments to expenditure on other regulated connection services		(3.88)	(4.47)	(5.17)	(5.60)	(5.98)
Adjustments to expenditure on other regulated retail services			(3.61)	(6.17)	(8.40)	(10.72)
Total recommended adjustments		**(108.56)**	**(110.85)**	**(111.31)**	**(151.61)**	**(132.34)**
Recommended forecast	**163.14**	**263.25**	**237.29**	**237.81**	**226.47**	**232.24**

Figure 5.2: Comparison of DLPC and Recommended Residual Growth CAPEX Forecast



5.4 RESIDUAL RENEWAL CAPEX

DLPC's forecast average annual residual renewal CAPEX over the forecast period RY 2010-14 is PhP717.29 Million. However, given that DLPC has not separated out residual growth from renewal expenditure over the historical period, historical renewal expenditure is not available as a benchmark to use in assessing whether or not the renewal expenditure was reasonable. We therefore relied on the SKM valuation report for guidance in estimating expected renewal CAPEX requirements, which we used as the basis for undertaking this review.

Appendix A of the SKM report provides the weighted average age and weighted average regulatory life of each line item. It does not provide the weighted average age or regulatory life of the full asset base and we have not undertaken this analysis. However the unweighted average age of the assets (excluding land) is 5.1 years compared to an unweighted average regulatory life of 24.7 years[18]. Hence we conclude that the age of the asset base is relatively low and we would expect the forecast renewal CAPEX requirements to reflect this.

For each line item in the SKM valuation we first calculated a benchmark renewal cost based on the assumption that the age profile for the particular line item was flat[19] and that individual assets were replaced as they reached the end of their regulatory life. This benchmark renewal cost was determined by dividing the (undepreciated) optimized replacement cost (ORC) for a particular line by the weighted average regulatory asset life for the line item.

We then calculated the ratio of SLPC's forecast average annual renewal cost[20] to the benchmark renewal cost for each line item. We expected this ratio to be significantly lower than 1.0, given that for all line items the weighted average asset age was

[18] The weighted average age and regulatory life of the asset base are both likely to be higher since the bulk of the asset value is in assets with a relatively long life.
[19] This assumption implies a weighted average age of half the weighted average regulatory life.
[20] The forecast average annual cost was DLPC's average annual renewal cost for the line item over the period RY 2010-14, taken form DLPC's revenue application template.

significantly lower than half the weighted average regulatory life[21]. This implies that the renewal requirement, and consequently our assessment ratio, should be relatively low.

We found the assessment ratios, calculated as described above were, indeed, much lower than 1.0 for most line items. We focused our review on those line items where the ratio was high and the total forecast renewal CAPEX was material.

5.4.1 Substation Equipment

DLPC is forecasting average annual CAPEX of PhP32.22 Million for the renewal of substation equipment. The calculated assessment ratio for all line items, except transformers and switchgear, was high – in the case of metering and communications equipment the ratio was 5.46, notwithstanding the fact that the average age of the assets was only 21% of the regulatory life.

In its revenue application DLPC provided a detailed program for the renewal of substation assets. It appeared to us that the program was developed assuming an environment where constraints on expenditure were low. For example, the program provided for the retrospective installation of on-line transformer monitoring of two power transformers per year and it was assumed that protection schemes and relays need to be replaced on a four-year cycle. We doubt that any of the regulators that we have worked with in Australia or New Zealand would allow such a generous program, particularly in the absence of a meaningful benefits analysis.

We recommend that the expenditure on the line items shown in Table 5.11 be adjusted so that the assessment ratio is set at 0.75. It will then be up to DLPC to prioritize its expenditure to match the budget and to not proceed with the lower priority projects or programs. We believe that our recommended expenditure will be more than sufficient to fund all necessary CAPEX.

Table 5.11: Recommended Adjustments to Residual Renewal CAPEX on Substation Equipment (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Protective Equipment						
DLPC Forecast		8.47	6.90	14.06	6.73	15.94
Recommended Adjustment		(2.73)	(1.16)	(8.32)	(1.00)	(10.20)
Metering and Control Equipment						
DLPC Forecast		5.13	6.93	10.24	5.78	10.06
Recommended Adjustment		(3.99)	(5.79)	(9.10)	(4.64)	(8.93)
Other Station Equipment						
DLPC Forecast		10.13	11.48	11.30	1.99	13.55
Recommended Adjustment		(2.16)	(3.51)	(3.33)	5.98	(5.58)
Totals						
DLPC Forecast		23.74	25.31	35.60	14.50	39.56
Recommended Adjustment		**(8.89)**	**(10.46)**	**(20.75)**	**0.35**	**(24.71)**

5.4.2 Power Operated Equipment

DLPC is forecasting average annual CAPEX of PhP5.79 Million for the renewal of non-network power operated equipment. The calculated assessment ratio for all line items except transformers and switchgear was 1.36 – notwithstanding the fact that the average age of the assets was only 18% of the regulatory life. We recommend that the

[21] The ratio of average age to regulatory life was lower than 28% for all network line items and 44% for all non network line items.

expenditure be adjusted to reflect an assessment ration of 0.75, as for the substation equipment in Section 5.4.1.

Our recommended adjustment is shown in Table 5.12.

Table 5.12: Recommended Adjustments to Residual Renewal CAPEX on Power Operated Equipment (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast		8.90	1.50	5.50	10.27	2.80
Recommended Adjustment		**(5.76)**	**1.64**	**(2.36)**	**(7.13)**	**0.34**

5.4.3 Information Systems Distribution

The benchmarking analysis described in Section 5.4 indicates the forecast residual renewal CAPEX on this line item is high, due to a one-off expenditure of $21.19 Million in RY 2013 on SCADA-EMS software. While the forecast major project cost is lower than the major project cost threshold DLPC provided a major project information summary on this project. This explained that DLPC was proposing to upgrade its SCADA system software and to use the same software for all the utilities under its umbrella.

We recommend that this cost be approved and that no adjustment be made to this line item.

5.4.4 Information Systems Non-network

DLPC has included a provision of PhP30.14 Million, plus unspecified local costs, for the purchase and implementation of a state-of-the-art works and asset management system in RY 2013.

We accept the usefulness of such a system when properly implemented and acknowledge that similar systems are routinely used by leading utilities internationally. We think it appropriate that the software be purchased by APC and shared by all APC utilities. As VECO has also included provision for a similar system in its revenue application we assume that is what is proposed. Notwithstanding this, no information has been provided on the forecast total cost of the system and how this cost would be shared by the different utilities.

Given this, and having regard to the overall magnitude of the DLPC CAPEX forecast, we recommend that this expenditure be deferred until the third regulatory period. During this regulatory period APC should carefully assess the requirements of the different utilities and to present a considered and properly costed proposal in the revenue application for the third regulatory period.

We further suggest that it is unrealistic for DLPC (or other APC utilities) to plan to install and integrate new works and asset management software at the same time as it is installing new SCADA software, since both systems require extensive input from technical staff to accurately populate the databases on which they rely. Deferring the purchase and implementation of the works and asset management system avoids the need to install two major software applications simultaneously and allows the organization to focus on properly implementing the new system only after the SCADA software is fully operational.

We recommend that expenditure on this line item be reduced to PhP7.43 Million, being the average annual expenditure on this line item over the other years of the forecast period.

This adjustment is shown in Table 5.13.

Table 5.13: Recommended Adjustments to Residual Renewal CAPEX on Non-Network Information Systems (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast					42.67	
Recommended Adjustment					(35.24)	

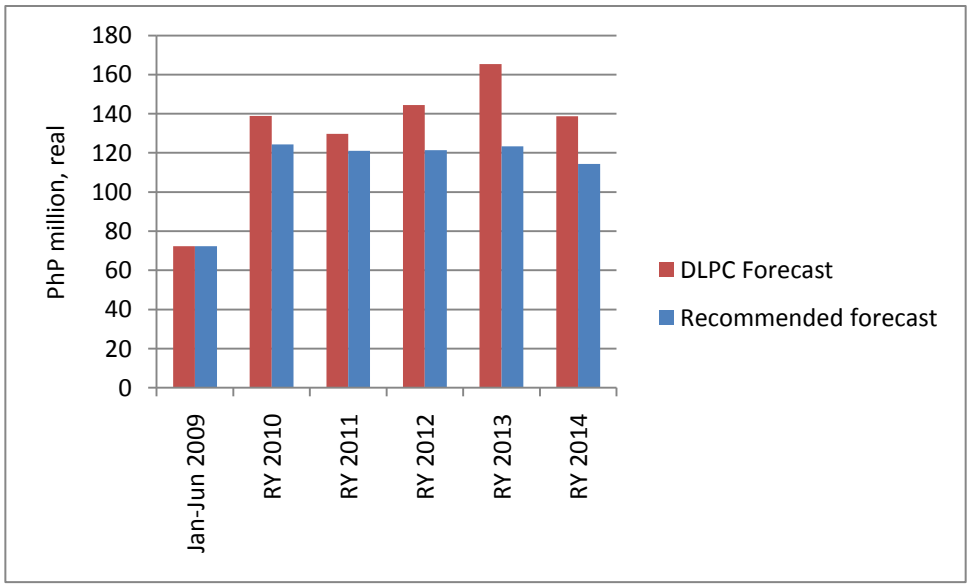
5.4.5 Summary

The recommended adjustments to DLPC's residual renewal CAPEX are summarized in Table 5.14 and the impact of these adjustments is shown in Figure 5.3.

Table 5.14: Adjustments to Residual Renewal CAPEX Forecast (PhP Million, real)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
DLPC Forecast	72.28	138.94	129.80	144.48	165.38	138.69
Adjustments to expenditure on substation equipment		(8.89)	(10.46)	(20.75)	0.35	(24.71)
Adjustments to expenditure on power operated equipment		(5.76)	1.64	(2.36)	(7.13)	0.34
Adjustments for deletion of works and asset management system.					(35.24)	
Total recommended adjustments		**(14.65)**	**(8.82)**	**(23.11)**	**(42.02)**	**(24.37)**
Recommended forecast	**72.28**	**124.29**	**120.98**	**121.37**	**123.36**	**114.32**

Figure 5.3: Comparison of DLPC and Recommended Residual Renewal CAPEX Forecast



6. SUMMARY OF RECOMMENDED TOTAL CAPITAL EXPENDITURE

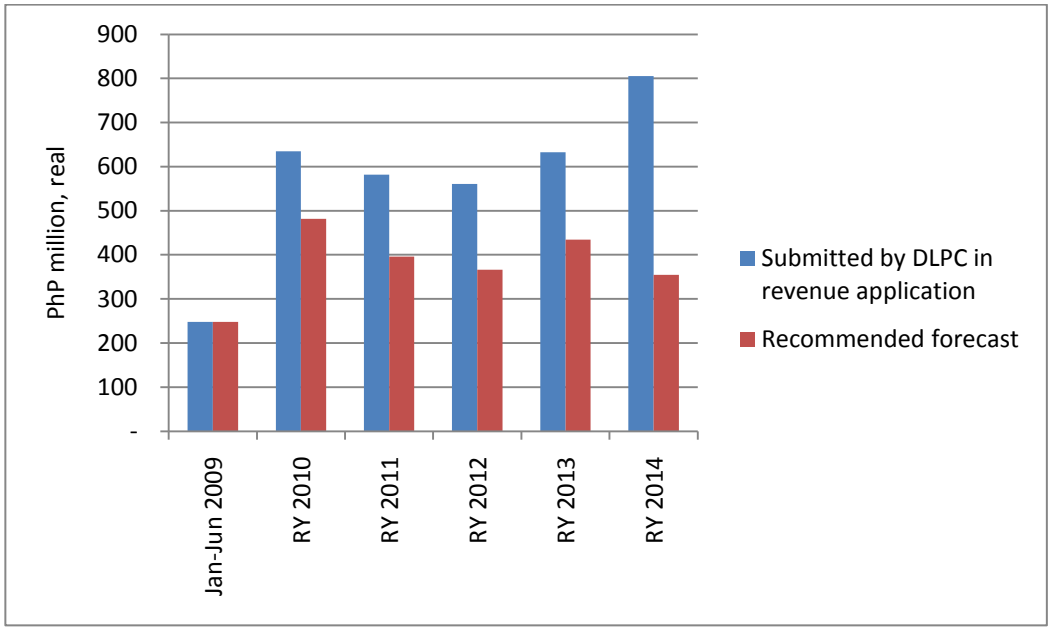
On the basis of the analysis for major projects and residual expenditure, we recommend the CAPEX shown in Table 6.1 be allowed for the forecast period January 2009 to June 2014. The total recommended CAPEX over the forecast period Jan 2009-Jun 2014 is PhP2,252.94 Million, a decrease of 35% on DLPC's revenue application value of PhP3,462.55 Million forecast total CAPEX over the same period.

Table 6.1: Adjustments to Forecast Total CAPEX (PhP Million)

	Jan-Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Submitted by DLPC in revenue application	247.67	634.52	581.82	560.40	632.88	805.26
Recommended forecast	247.67	481.3	396.11	365.91	434.59	354.45

These recommended adjustments to forecast CAPEX is shown graphically in Figure 6.1 below.

Figure 6.1: Recommended Adjustments to Forecast Total CAPEX (PhP Million)



Our recommended forecast represents a reduction of PhP79.26 Million as against the forecast in the revenue application when measured over the period 1 Jan 2009 to 30 June 2014.

The breakdown of the recommended forecast expenditure into the ERC's standard expenditure categories shown in Table 6.2 and Figure 6.2.

Table 6.2: Breakdown of Recommended Forecast Expenditure (PhP Million, real)

	Jan –Jun 2009	RY 2010	RY 2011	RY 2012	RY 2013	RY 2014
Major Projects		87.47	25.00		75.40	
Growth	163.14	263.25	237.29	237.81	226.47	232.24
Renewal	72.28	124.29	120.98	121.37	123.36	114.32
Refurbishment	12.24	6.29	12.84	6.73	9.36	7.89

Figure 6.2: Breakdown of Recommended Forecast Expenditure (PhP Million, real)