



**PB ASSOCIATES**

**REVIEW OF FORECAST EXPENDITURE:  
SECOND REGULATORY PERIOD**

**Iligan Light and Power Incorporated**

**Prepared for**

**ENERGY REGULATORY COMMISSION**

26 September 2008

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## EXECUTIVE SUMMARY

### CAPITAL EXPENDITURE (CAPEX)

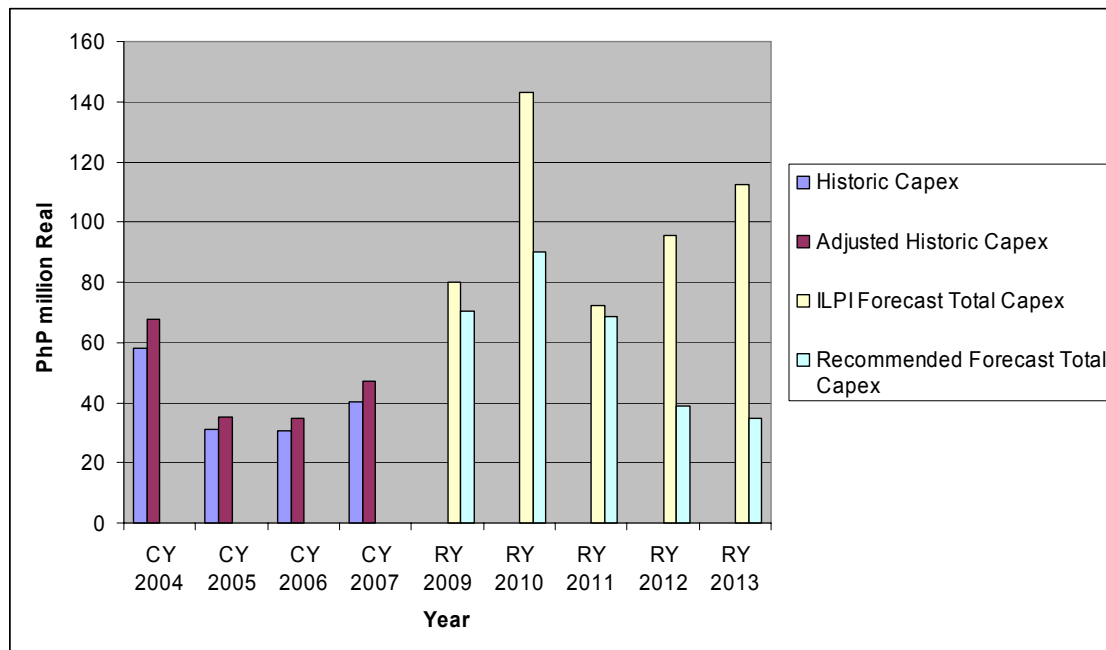
We recommend that the Energy Regulatory Commission (ERC) make the following adjustments to the forecast capex proposed by Iligan Light and Power Incorporated (ILPI):

#### Forecast Capital Expenditure (PhP million, real 2008)

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013	TOTAL <sup>1</sup>
<b>Forecast Capex (Revenue Application)</b>	<b>79.86</b>	<b>142.94</b>	<b>72.33</b>	<b>95.57</b>	<b>112.58</b>	503.28
Recommended Adjustments						
Luinab Substation Transformer Capacity		0.91				0.91
Deletion of Zamora Substation			(14.44)			(14.44)
Deletion of TransCo Asset Purchase		(37.96)		(28.13)	(9.04)	(75.13)
Deletion of 69 kV Tie Lines				(14.86)	(15.82)	(30.68)
Deletion of Kiwalan Switching Station					(37.81)	(37.81)
Rehabilitation of Power Substations	(3.94)	(10.05)	33.77	3.94		(23.72)
Deletion of TransCo Asset Rehabilitations			(5.69)		(7.18)	(12.87)
Residual Capex Adjustment	(5.50)	(5.61)	(17.35)	(17.72)	(7.88)	(54.06)
<b>Recommended Capex</b>	<b>70.42</b>	<b>90.23</b>	<b>68.62</b>	<b>38.80</b>	<b>34.85</b>	(302.92)
<b>Total Adjustment</b>	<b>(9.44)</b>	<b>(52.71)</b>	<b>(3.71)</b>	<b>(56.77)</b>	<b>(77.73)</b>	(200.36)
<b>Impact of Total Adjustment</b>	<b>(11.8%)</b>	<b>(36.9%)</b>	<b>(5.1%)</b>	<b>(59.4%)</b>	<b>(69.0%)</b>	(39.8%)

Note 1: Total for RY 2009-13

#### Comparison of Recommended Capex with ILPI's Historic and Forecast Capex (PhP million, real 2008)



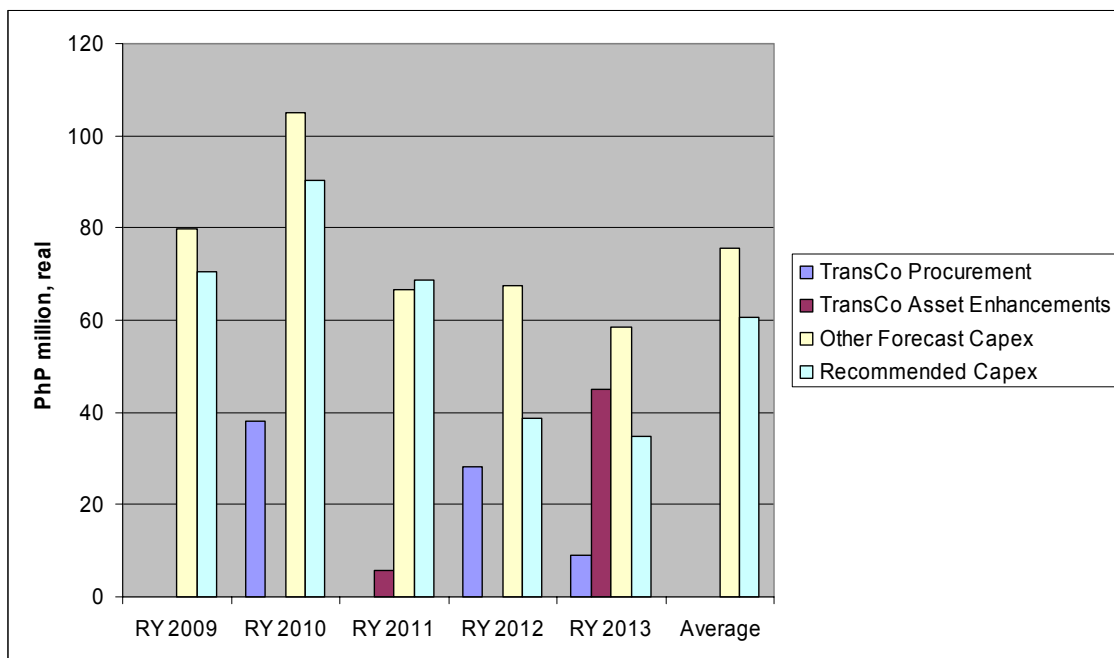
The key findings of our capex review are as follows:

- ILPI's historic capex includes materials costs only, whereas its forecast capex includes both materials and installation costs. Hence the historic and forecast capex streams submitted in ILPI's revenue application are not directly comparable. We have therefore adjusted the CY 2004-07 historic capex to include estimated installation costs and used this adjusted expenditure stream for comparison purposes. The impact of the adjustment is shown in the above diagram.
- ILPI is proposing to construct a new 69/13.8 kV substation at Luinab. We recommend that this project be approved as it will relieve the existing very high utilization of its power transformers. We have suggested that the capacity of the power transformer be increased from 20/25 MVA to 20/30 MVA as the increased forced air capacity would be needed in the event of an n-1 contingency arising. We have made a minor adjustment to ILPI's estimated cost to provide for this.
- ILPI is also proposing to construct a small 5 MVA substation at Zamora using an old semi-retired transformer. We recommend that capex for this project not be approved as we believe this to be an "opportunistic" proposal that is not consistent with what we consider would be an optimal network development plan. In our view the cost of this development is high for the additional transformer capacity provided due to the cost of substation infrastructure such as switchgear.
- ILPI has provided insufficient information to allow us to determine a reasonable capex for the purchase of TransCo subtransmission assets. We are also concerned that, if a capex provision is made for the acquisition of these assets, any delay in completing the transaction would result in a windfall gain to ILPI. Customers would pay twice for the period of any delay, firstly through the transmission charge and secondly through the distribution rate. Furthermore, we think this would make it very difficult for the ERC to decline to approve any purchase contract. We have therefore recommended that capex for the purchase of subtransmission assets is not approved and that this issue be dealt with outside of the RDWR process.
- ILPI has proposed the construction of two additional 69 kV tie lines, which it believes will improve the security of supply to customers. We recommend that the required capex not be allowed because the existing 69 kV TransCo lines and ILPI's existing 69 kV tie line already provide a level of security consistent with the n-1 criteria specified in Table D1 of the RDWR.
- ILPI has proposed the construction of a new 69 kV switching station that would ensure that directly connected customers would be connected to the network through a circuit breaker. We recommend that the required capex not be allowed as any benefits to ILPI's existing customers could be provided more cost effectively. This project is also contingent on the purchase of the TransCo assets proceeding and would result in connection assets to be used by customers directly connected to the 69 kV lines currently owned by TransCo being paid for by ILPI's existing customers.
- ILPI has proposed that capex be provided for the rehabilitation of its existing two power substations. We recommend that that capex be allowed, particularly in respect of the Pala-O substation, which was constructed using second hand equipment and is in poor condition. We further recommend that sufficient capex be included in this project to allow for the replacement of the existing Pala-O transformer. The transformer was manufactured in 1967 and is operating at high load. ILPI is currently unable to get this transformer out of service for maintenance or testing and we believe that there is a high probability of it failing. Our recommendation includes the additional capex required for this work, which has been reallocated from projects that we recommend not be approved.
- ILPI has proposed that capex be provided for the rehabilitation of the subtransmission assets that it will purchase from TransCo. As this work is contingent upon the acquisition of the TransCo assets proceeding we recommend that it not be approved. The need for this work should be considered by ERC in conjunction with its consideration of the sale and purchase of the subtransmission assets.

- We recommend that the residual miscellaneous capex for RY 2009 be reduced by PhP 5.5 million, as this expenditure is in excess of the average annual historic expenditure on this line item and was not justified by ILPI in its revenue application.
- We have had some difficulty comparing ILPI's historic and forecast capex as the historic capex appears to include expenditure on significant one-off projects that were not specifically identified in the revenue application. Furthermore expenditures on a number of ongoing quality improvement projects were treated as major projects in the revenue application. We resolved this difficulty by reclassifying these quality improvement projects as residual capex for the purposes of this review. We then set the forecast residual capex for the period RY 2010-13 at the estimated average real historic capex, after adjusting out the estimated cost of the unidentified one-off projects. The recommended forecast residual capex for RY 2009 is higher, but this additional expenditure was justified in the information submitted by ILPI (except for the above unexplained miscellaneous capex component).

A high proportion of our proposed overall reduction in ILPI's forecast capex is due to our recommendation not to include the acquisition of the TransCo subtransmission assets and follow-on projects. There is nevertheless also a reduction in the capex forecast by ILPI for the development of its existing network, notwithstanding the reallocation of expenditure to provide for the replacement of the Pala-O transformer. This is shown graphically in the diagram below. All recommended capex is for enhancements to ILPI's existing network.

**Comparison of Recommended Capex with ILPI's Disaggregated Forecast (PhP million, real 2008)**



**OPERATIONS AND MAINTENANCE EXPENDITURE (OPEX)**

We recommend that the ERC make the following adjustments to the opex proposed by ILPI.

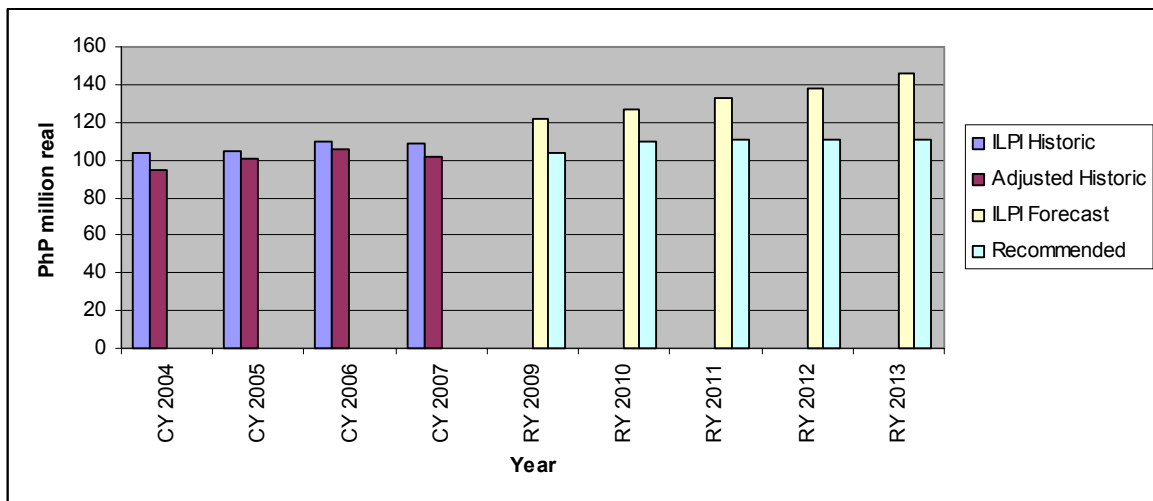
**Comparison of ILPI and Recommended Forecast Opex (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013	Total <sup>1</sup>
<b>Distribution System Operations</b>						
Revenue Application Forecast	19.10	20.23	20.17	20.89	21.74	102.14
Model	18.18	19.45	20.17	20.15	20.26	98.21
DSOAR Adjustment	-	(0.19)	(0.40)	(0.60)	(0.81)	(2.01)
<b>Recommended Opex</b>	<b>18.18</b>	<b>19.26</b>	<b>19.76</b>	<b>19.55</b>	<b>19.45</b>	<b>96.20</b>
<b>Distribution System Maintenance</b>						
Revenue Application Forecast	15.99	17.50	19.44	20.11	20.90	93.94
Model	15.46	16.56	17.18	17.19	17.30	83.69
DSOAR Adjustment	-	(0.17)	(0.34)	(0.52)	(0.69)	(1.72)
<b>Recommended Opex</b>	<b>15.46</b>	<b>16.39</b>	<b>16.84</b>	<b>16.67</b>	<b>16.61</b>	<b>81.98</b>
<b>Regulated Retail Services</b>						
Revenue Application Forecast	26.76	24.81	25.01	25.67	26.40	128.65
<b>Recommended Opex</b>	<b>21.90</b>	<b>23.72</b>	<b>24.05</b>	<b>24.59</b>	<b>25.15</b>	<b>119.41</b>
<b>Administrative &amp; General Expenditure</b>						
Revenue Application Forecast	60.18	64.02	68.18	71.34	76.55	340.28
<b>Recommended Opex</b>	<b>47.96</b>	<b>50.11</b>	<b>49.80</b>	<b>49.48</b>	<b>49.20</b>	<b>246.55</b>
<b>Totals</b>						
Revenue Application Forecast	122.04	126.56	132.81	138.01	145.58	665.00
<b>Recommended Opex</b>	<b>103.51</b>	<b>109.48</b>	<b>110.45</b>	<b>110.29</b>	<b>110.41</b>	<b>544.14</b>
<b>Recommended Adjustment</b>	<b>(18.5)</b>	<b>(17.1)</b>	<b>(22.4)</b>	<b>(27.7)</b>	<b>(35.2)</b>	<b>(120.9)</b>
Percentage Adjustment	(15.2%)	(13.5%)	(16.8%)	(20.1%)	(24.2%)	(18.2%)

Note 1: Total for RY 2009-13

Source: PB Associates

A comparison between ILPI's actual opex, its forecast opex and our recommended opex over the second regulatory period is shown in the graph below.

**Comparison of Recommended Opex with ILPI's Historic and Forecast Opex (PhP million, real 2008)**

The key findings of our opex review are as follows:

- Due to the different allocation of installation related capital costs in the historic and forecast opex, the estimated costs associated with the installation of new capital assets were adjusted out of ILPI's reported historic opex to provide a more valid comparison with its opex forecast. This adjustment is shown in the above diagram.
- As ILPI provided insufficient information on how it derived its forecast opex, we were unable to review its methodology for reasonableness. Therefore we used PB Associates' opex forecasting model to estimate ILPI's future opex needs and adjusted for the differences between ILPI's forecast and the required opex determined from our modelling. Our modelling was based on ILPI's actual opex for CY 2007, after adjustment to remove the estimated capex related installation expenditures. We also made some relatively minor adjustments to the base year costs to remove one-off expenditures that would not be incurred over the forecast period.
- As part of this review we benchmarked ILPI's operational efficiency against the other first and second entry point IOUs. This exercise indicated ILPI's opex is relatively high in relation to its size, probably due to higher staffing levels. Our model therefore assumed a 1% per annum real reduction in total labor costs. We envisage that this efficiency gain would be achieved through better utilization of staff resources rather than through a real reduction in unit labor rates. Our modelling approach also envisages that labor efficiency gains will be achieved incrementally.
- Other reasons for our recommended opex being lower than forecast by ILPI could include:
  - the exclusion of opex related to the assets that were not included in our recommended capex; and
  - our modelling assumption that 90% of administrative and general expenditures are fixed and will not increase in real terms over the forecast period;
- Notwithstanding our modelled real labor cost reduction, our opex forecast includes the expenditure proposed by ILPI for the establishment of a call centre. We have also provided for the additional insurance costs requested by ILPI.
- Consistent with the final determination for the first entry point IOUs, we have made a reduction to the forecast opex to account for the expected progressive introduction of Distribution Services Open Access Rules (DSOAR). If this provision was not made, then any charges made to customers for the provision of contestable distribution services during the second regulatory period would also be recovered through the distribution wheeling rate. This would result in a double recovery of these charges.
- At the end of the second regulatory period we estimate that ILPI's key performance indicator of total opex per kWh will reduce from a current level of 0.58 to 0.40, when measured in real 2008 PhP.

## **TAXES, LEVIES AND DUTIES**

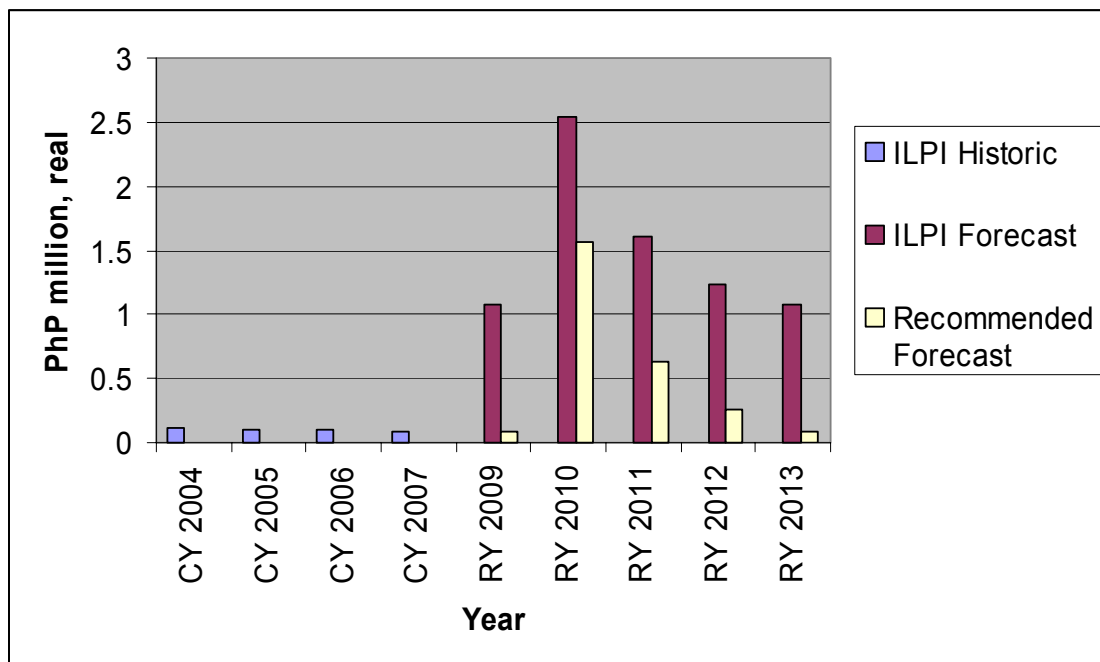
We recommend that the ERC make following reductions to ILPI's forecast expenditure on taxes, levies and duties:

**Forecast Taxes, Levies and Duties (PhP million, real 2008)**

Year	CY 2008	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013	Total <sup>1</sup>
<b>Proposed in ILPI's Revenue Application</b>							
Taxes, Levies and Duties	0.21	1.07	2.54	1.61	1.24	1.07	7.75
<b>Adjustments</b>							
Real Property Tax - Machineries	-	0.978	0.978	0.978	0.978	0.978	4.888
Real Property Tax - Proposed Building	0.006	0.006	0.006	0.006	0.006	0.006	0.034
Regulatory Reset Expert Fees	0.112	-	-	-	-	-	0.112
<b>Recommended Provision for Taxes, Levies and Duties</b>	<b>0.09</b>	<b>0.09</b>	<b>1.56</b>	<b>0.63</b>	<b>0.26</b>	<b>0.09</b>	<b>2.72</b>

Note 1: Total for RY 2009-13

A comparison between ILPI's actual taxes, levies and duties expenditure, its forecast expenditure and our recommended taxes, levies and duties expenditure is shown in the chart below.

**Comparison of Recommended Taxes, Levies and Duties with ILPI's Historic and Forecast Taxes, Levies and Duties (PhP million, real 2008)**

The key findings of our taxes, levies and duties review are as follows:

- The reduction in the provision for taxes levies and duties is due primarily to a reduction in the provision for real property taxes. These are new taxes that ILPI has not paid in the past and where its future liability has still to be legally established.
- We have also excluded regulatory reset expert fees for CY 2008.

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## 1. INTRODUCTION

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The Energy Regulatory Commission (ERC) has promulgated a performance-based form of regulation (PBR) for investor owned electricity distribution utilities (IOUs) in the Philippines. Under the PBR framework an IOU will be subject to a price cap for the delivery of distribution wheeling services. The reset process for the setting of the price cap for the three IOUs entering the PBR at the second entry point is currently underway. This process will result in the setting of a maximum price path that will determine the maximum average price (MAP) that an IOU can charge for the provision of electricity distribution services in each year of the Second Regulatory Period (which commences on 1 April 2009 and ends on 31 March 2013).

The mechanism for the calculation of the price cap and the procedure and timelines for the introduction of this cap are described in the Rules for Setting the Distribution Wheeling Rate (RDWR), which was released by the ERC on December 13 2006<sup>1</sup>. The ERC has also formulated its position on the reset process, which is set out in a Position Paper dated March 14 2007<sup>2</sup>.

An important requirement of the reset process going forward is the review of the expenditure forecasts submitted by the IOUs as part of the rate setting process under PBR. These expenditure components are critical to the determination of the revenue that IOUs will require for the provision of regulated distribution services over the second regulatory period and on which the price caps will be based.

The RDWR require that the expenditure forecasts provided by an IOU be reviewed by a Regulatory Reset Expert as part of the PBR regulatory reset process. Parsons Brinckerhoff Associates (PB Associates) has been engaged by the ERC to review the expenditure forecasts of the three IOUs that will be entering PBR at the second entry point.

The following expenditure forecasts form part of this review process:

- capital expenditure (capex);
- disposal of fixed assets;
- operating and maintenance expenditure (opex); and
- taxes (other than corporate income tax), levies and duties.

The three IOUs entering PBR at the second entry point are:

- Cotabato Light and Power Company (CLPC);
- Iligan Light and Power Incorporated (ILPI); and
- Mactan Electric Company (MECO).

This report presents the PB Associates' review of the expenditure forecasts of ILPI. These forecasts were submitted to the ERC as part of ILPI's revenue and performance incentive scheme application (revenue application) on May 23, 2008.

In undertaking this review we have relied on the accuracy of the information provided to the ERC by ILPI. 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

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<sup>1</sup> *Rules for Setting Distribution Wheeling Rates for Privately Owned Distribution Utilities Entering Performance Based Regulation (Second and Later Entry Points)*, Energy Regulatory Commission, December 13 2006.

<sup>2</sup> *Regulatory Reset for the October 2008 to September 2012 Regulatory Period for Privately Owned Distribution Utilities subject to Performance Based Regulation, Position Paper*, Energy Regulatory Commission, March 14 2007. Note that the start and finish dates of the regulatory period to which this Position Paper applies were subsequently changed to April 1 2008 and March 31 2013 respectively, by ERC Resolution No 24 Series of 2007, dated October 24 2007.

responsible for any conclusions based on misleading or inaccurate information provided to us.

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## 2. CAPITAL EXPENDITURE

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### 2.1 REVIEW CRITERIA

The capex review has been undertaken on the basis that proposed expenditure should only be recommended for approval if it is:

1. used for the provision of regulated distribution services;
2. either:
  - required, in that the expenditure is unable to be avoided if distribution services to customers are to continue over time to be provided in accordance with the Philippines Distribution Code and the IOU's other legal and regulatory obligations; or
  - discretionary, and the IOU is able to demonstrate that the value to customers of the benefits that it expects to receive through making the expenditure outweighs the cost of the expenditure, after taking due account of any uncertainties in the assumptions used in this analysis; and
3. economically efficient in that the timing of the expenditure is appropriate and the level of expenditure is no higher than necessary to achieve the required outcome.

### 2.2 OVERVIEW OF EXISTING DISTRIBUTION NETWORK

ILPI's franchise area is geographically long and narrow and customers are supplied from a 13.8 kV backbone three wire distribution line that runs the length of its supply area. This backbone line is segregated into four feeders separated by normally open interconnectors and is supplied by two points of injection from TransCo's 69 kV network, located at Pala-O and Kiwalan. A fifth feeder from the Pala-O substation supplies the central business district. Spur distribution lines are tapped off the 13.8 kV feeder backbones as required.

The Pala-O and Kiwalan substations are connected by short ILPI-owned spur lines to existing TransCo 69 kV transmission lines that interconnect the Agus 6 power station switchyard and TransCo's Lugait substation. In addition, ILPI has recently completed its own new 69 kV tie line between its Pala-O and Kiwalan substations, allowing both substations to be supplied in the event of an outage of one of the TransCo connection points.

Until recently ILPI had a third point of injection from TransCo's 69/13.8 kV Overton substation, which fed into the southern end of its backbone network at 13.8 kV. However this injection point was limited to a maximum off-take of 5 MVA because of the condition of both the power transformer, (which was manufactured in 1947 and was shared with other grid users) and the 13.8 kV circuit breaker controlling the ILPI feeder. Due to the age and condition of these TransCo assets, and also because of concerns over the disputed ownership of the land on which the substation is located, ILPI considers that further investment on this site would not be prudent. It has therefore decided to relinquish the Overton connection point and plan further network development on the basis that the Overton point of injection will no longer be used.

Apart from ILPI, TransCo also supplies three directly connected industrial customers from its 69 kV network between the Agus 6 switchyard and Lugait. In addition, ILPI supplies its own two largest industrial customers at 69 kV from its own network. A new Guisano mall is also under construction in Iligan City and will be connected at 69 kV to ILPI's own network by late 2008.

The two substations supplying ILPI's 13.8 kV distribution network, Pala-O and Kiwalan, are single transformer substations, with transformer capacities of 32 MVA and 12 MVA respectively<sup>3</sup>. The Pala-O transformer was first commissioned in 1967. It was purchased second hand by ILPI in 1996 and, while it was refurbished before installation in its current location, the extent of this refurbishment is not clear. The current condition of its oil and windings is not known but we consider that the unit should be considered to have a high risk of failure due to its age and high loading. The Kiwalan transformer was first commissioned in 1998 and is assumed to be in good condition. ILPI currently has two spare 5 MVA transformers available, both manufactured in 1977. One is located in the Pala-O substation yard to provide limited back-up for the in-service 32 MVA unit and the other is stored in the Luinab pole yard.

The 2008 non-diversified maximum demand on the 13.8 kV distribution network is 32.8 MW or about 35.3 MVA at 0.93 power factor. Hence the available transformer capacity is approximately 80% utilized at peak demand. While this is relatively high when compared to other Philippines utilities<sup>4</sup>, more worrying is the deficiency of approximately 18 MVA (after energization of the 5 MVA standby unit) at peak load should there be a failure of the 32 MVA Pala-O transformer. Given the age and present loading on this unit, we believe that such a premature failure is a very credible contingency event.

### 2.3 DEMAND FORECAST

It is not within the terms of reference for this review to undertake a detailed study of the forecasts of energy sales, peak demand and customer numbers included in ILPI's revenue application. However, as load driven capex is dependent on the growth in peak demand on the network, we have reviewed the demand forecast at a high level in order to be satisfied that the assumptions made by ILPI as the basis for its capex forecast are reasonable.

In ILPI's case, it is the demand on the 13.8 kV network that is of most interest as this will be an important driver for the installation of additional power transformer capacity. While much of its forecast capex is related to the purchase and upgrading of TransCo's 69 kV network, this expenditure is driven by commercial and reliability considerations rather than growth. ILPI is planning to construct two new substations during the second regulatory period and while this work is also driven largely by reliability considerations, the timing of the work and the size of the new transformers will be strongly influenced by the forecast growth in the demand on the 13.8 kV distribution network. We also look at the total load on the distribution network rather than the load on individual substations since there is a relatively high level of interconnectivity between the different 13.8 kV feeders. Hence the distribution network can be used to transfer load between substations. In these circumstances it is the overall 69/13.8 kV transformation capacity in relation to the total load on the 13.8 kV network that is of primary interest.

In reviewing ILPI's forecast 13.8 kV network demand we nevertheless first consider its forecast energy requirements, since the demand forecast in the revenue application was based on its energy forecast<sup>5</sup>. Furthermore we would expect the demand forecast to generally track the energy forecast since any significant divergence between the two over time is likely to be unsustainable<sup>6</sup>.

<sup>3</sup> The Pala-O transformer is rated at 25/32/40 MVA. However, as no provision is made for forced oil cooling, its forced air rating of 32 MVA is the current maximum rated continuous output of the unit. The Kiwalan transformer is rated at 10/12 MVA.

<sup>4</sup> MERALCO, which has a high level of load transfer capacity at distribution voltage level, works on the basis of 70% power transformer utilization. CEPALCO used a similar utilization level to justify the installation of additional transformer capacity during the second regulatory period.

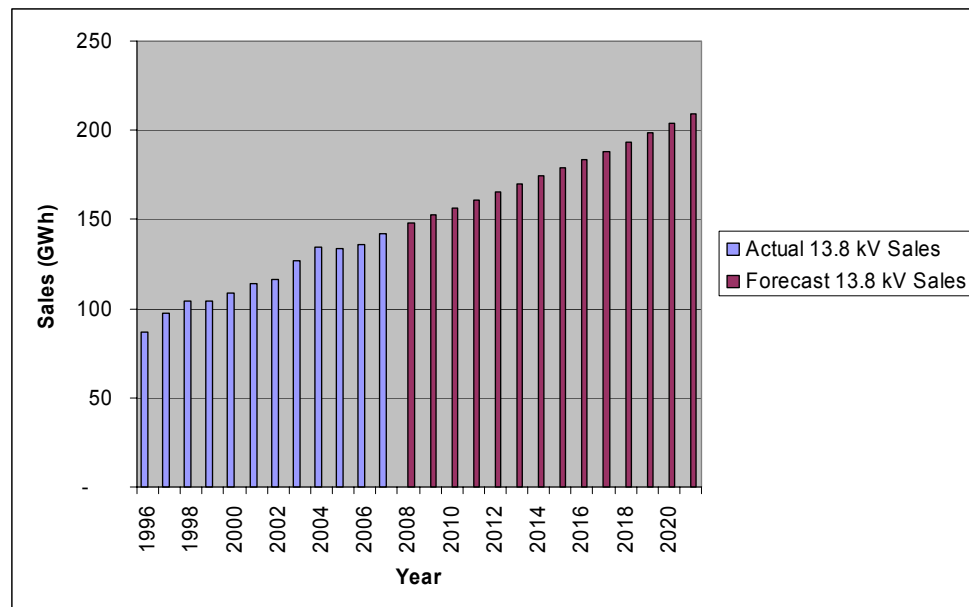
<sup>5</sup> ILPI Revenue Application, Schedule H4, Section 2.

<sup>6</sup> Such a divergence implies a changing load factor. While we would expect load factor to fluctuate from year to year, we would not normally expect continuing changes over time, as this would imply a significant change in the nature of the load being supplied.

ILPI has forecast its energy consumption using a mathematically sophisticated polynomial curve fit method, which takes the actual energy consumption over the period 1996-2007 and extrapolates the resulting curve through to 2021. The energy forecasts in the revenue application were extracted from this extrapolation. We have not considered the detail of ILPI's mathematical derivation but limited our review to a high level sanity check.

The actual and forecast energy sales to customers connected at 13.8 kV and below are shown in Figure 2.1. Unlike ILPI, we have not included network losses, as a proportion of these are at 69 kV and we are primarily concerned with the load on ILPI's 69/13.8 kV transformers.

**Figure 2.1: Actual and Forecast 13.8 kV Energy Sales (GWh)**

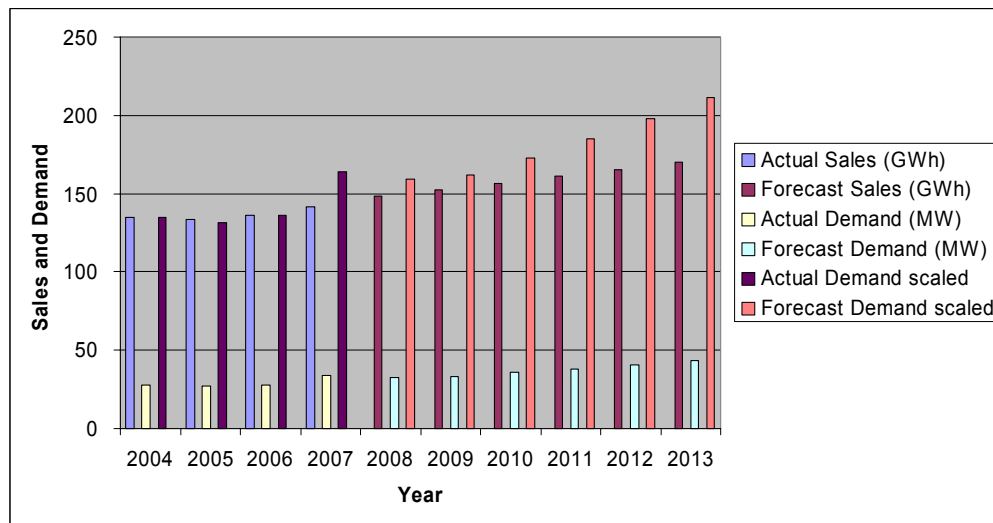


From Figure 2.1 it can be seen that actual energy sales are characterized by years of high growth such as 1997(12.9%) and 2003 (8.8%) and other years (1999, 2005) where the growth was very low or even marginally negative. Thus the historic growth rates depend on the period over which the growth is measured. For example, growth over the period 1996-2007 was 4.7% per annum. This reduces to 3.5% per annum if measured over the period 1998-2007 and even further to 2.0% per annum for the period 2004-2007. We believe that more weight should be given to sales figures in the recent past as these reflect current economic circumstances and the forecast of interest is over a relatively near-term window. However basing a forecast only on the 2% growth indicated by the historic sales in the revenue application would give no weight to the strong growth experienced in 2003 and 2004 and may also not adequately take account of the sales rebound in 2007. On this basis, ILPI's forecast annual growth in energy sales of 2.9% over the period 2007-2013 seems reasonable.

Figure 2.2 shows ILPI's actual and forecast energy sales to customers connected at 13.8 kV and below for the period 2004-2013 as well as the corresponding actual and forecast demand. In addition the actual and forecast demands are "scaled". The actual demand for 2004 has been multiplied by a factor of 4.85 so that the 2004 energy sales is shown graphically as being numerically equal to the scaled 2004 demand. Actual and forecast demands for the period 2005-2013 have also been scaled using the same scaling factor. This technique allows the energy sales growth rates to be directly compared with growth rates in demand.

It can be seen from the figure that over the period 2004-06 demand closely tracked energy sales, while in 2007 demand increased proportionally more than energy sales. This may be due to the inclusion of the load supplied from the Overton point of connection and based on this assumption we consider that the high 2007 peak, rather than being an anomaly, is actually a reasonable base for projecting forecast 13.8 kV network peak demands<sup>7</sup>. However it can be seen from Figure 2.2 that ILPI has predicted a marginally increasing load factor in 2008-2009 but that over the second regulatory period 2010-2013 the load factor will progressively reduce as the growth in demand outstrips the growth in energy sales. We believe progressive load factor reductions of the magnitude implied by ILPI's demand forecast over the period 2010-13 are unsustainable. It is more reasonable to assume that demand will increase after 2007, at the same rate as energy sales, namely 2.9%. This adjusted forecast is shown in Table 2.1 and graphically in Figure 2.3. This adjustment reduces ILPI's forecast 2013 13.8 kV network demand by 7.7%.

**Figure 2.2: Actual and Forecast Energy Sales and Demand**



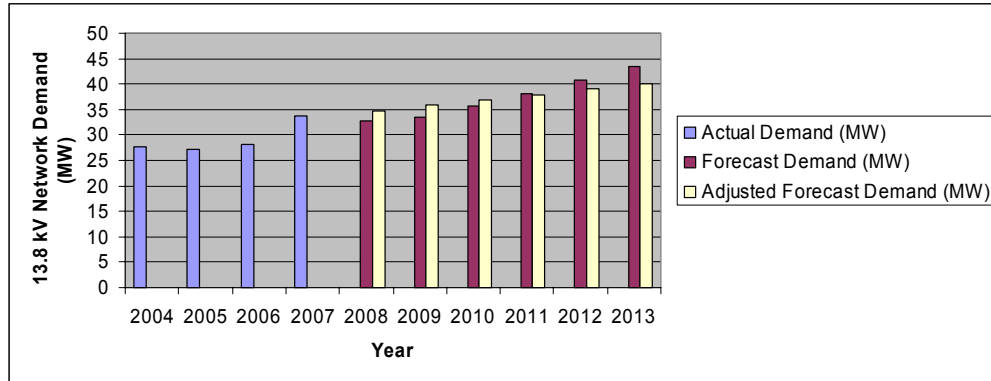
**Table 2.1: Actual and Adjusted Forecast 13.8 kV Peak Demand**

	2008	2009	2010	2011	2012	2013
Actual Forecast (MW)	32.8	33.4	35.6	38.2	40.8	43.5
Adjusted Forecast (MW)	34.8	35.8	36.9	37.9	39.0	40.2

We emphasise that this analysis is focused on issues pertinent to the capex review. Hence the energy sales and the peak demands considered in this analysis relate only to customers connected at 13.8 kV and below. The energy consumption and peak demands of ILPI's 69 kV customers or of customers directly connected to the TransCo subtransmission network are not included.

<sup>7</sup> Correspondence between ILPI and TransCo provided following the clarificatory meeting indicates that supply from the Overton metering point may not have been available between June 2004 and February 2007. If this is the case this assumption is not correct since the reported peak loads in 2005-06 would include the Overton load. We have nevertheless adopted a conservative approach for this analysis and used the 2007 peak demand as the basis for our proposed demand forecast.

**Figure 2.3: Actual and Adjusted Forecast 13.8 kV Peak Demand**



**2.4 OVERVIEW OF HISTORIC AND FORECAST CAPITAL EXPENDITURE.**

ILPI’s historic and forecast capex, taken from the capex template provided with its revenue application, is shown in Table 2.2 and Figure 2.4.

ILPI advised during the clarificatory meeting that its reported historic (RY 2004-07) capex included materials only, whereas the budgeted and forecast includes both materials and installation costs. We have therefore added in the estimated installation costs associated with the historic capex to obtain an adjusted historic capex<sup>8</sup>. This adjustment is intended to make the historic capex and opex streams directly comparable with forecast capex and opex.

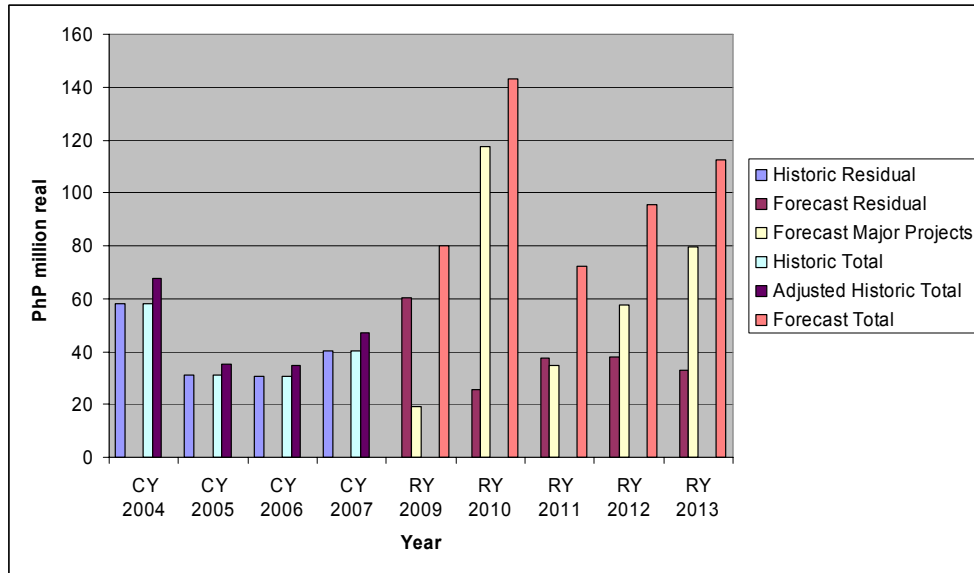
We have not presented the budgeted capex for CY 2008. This is because there is a nine-month overlap between CY 2008 and RY 2009 and if the budgeted capex for CY 2008 was included in the analysis, expenditure over this overlapping nine-month period would be included twice. This could potentially distort the analysis.

**Table 2.2: Historic and Forecast Capex (PhP million, real 2008)**

	CY 2004	CY 2005	CY 2006	CY 2007	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Historic Residual	58.18	30.95	30.49	40.26					
Forecast Residual					60.52	25.50	37.52	37.76	33.01
Forecast Major Projects					19.33	117.44	34.81	57.81	79.57
Historic Total	58.18	30.95	30.49	40.26					
Adjusted Historic Total	67.60	35.07	34.64	47.07					
Forecast Total					79.86	142.94	72.33	95.57	112.58

<sup>8</sup> Installation costs were estimated on the basis of the installation cost margins for the different asset types that were derived for the asset valuation. Each year’s adjustment has also been deducted from the historic opex submitted by ILPI to provide the adjusted historic opex (which does not include capex related costs). While this adjustment will indicate a higher capex requirement it will also indicate lower opex and so the overall impact on the allowed revenue is assumed to be minor.

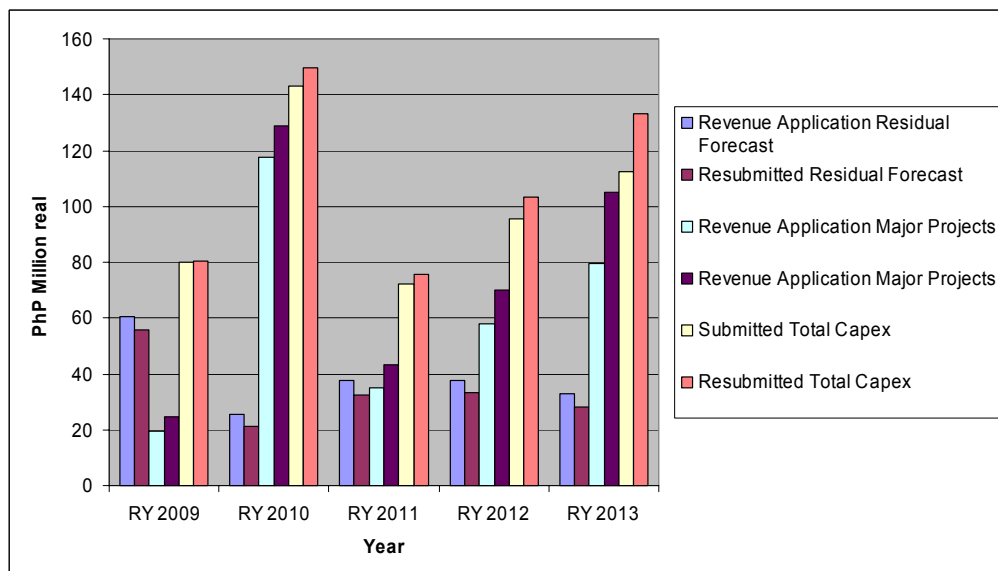
**Figure 2.4: ILPI Historic, Budget and Forecast Capex (PhP million, real)**



Examination of Figure 2.4 indicates that ILPI's forecast total capex is substantially higher than its adjusted historic capex, which is mainly due to the inclusion of major projects in the forecast. There were no major projects included in the historic capex, even though ILPI substantially completed the construction of a 69 kV tie line between the Pala-O and Kiwalan substations over this period. Most of the procurement for this 69 kV tie-line would have occurred in CY 2007 and we assume that this is the reason for the high capex that year. Forecast residual capex appears slightly lower than expected when compared with historic capex, except for the notable hump in the RY 2009 forecast.

Following discussions at the clarificatory meeting about discrepancies in the capex information provided in the revenue application, ILPI submitted a "corrected" capex template, with even higher forecast capex. A comparison between the capex forecast in the revenue application template and the resubmitted template is shown in Figure 2.5.

**Figure 2.5: Comparison of Submitted and Resubmitted Forecasts (PhP million, real)**



It can be seen from Figure 2.5 that the resubmission lowered the residual capex forecasts and increased the major project forecast. However the increase in the major project forecast was greater than the amount by which the residual capex forecast was lowered, leading to an overall increase in the total forecast.

The problem appears to be that, in addition to a number of one-off projects, ILPI submitted major project sheets for a number of initiatives for discretionary ongoing projects that are residual in nature. These were:

- Line Loss Management Program (Load Centering);
- Distribution Transformer Replacement and Retrofits;
- Line Revamping; and
- Pole Replacement.

These projects, taken together, represent a series of initiatives to improve the quality of ILPI's high voltage distribution and low voltage networks in order to reduce losses and improve the quality of supply to consumers. They are ongoing programs that have continued for a number of years. ILPI has provided an allocation for each of these initiatives in its capex forecast, and these allocations are shown and justified on major project sheets. Unfortunately the historic expenditures related to these initiatives are not separately identified and have been included in the reported historic capex, all of which is shown as residual. We suspect that some (but not all) of the historic expenditure on the above initiatives may have been extrapolated into the residual capex forecast and, to the extent that this has been done, this expenditure has been double counted in the forecast.

We tried to adjust for this by asking ILPI at the clarificatory meeting to provide the historic expenditure for each of the above initiatives. Our intention was to remove this expenditure from the reported historic capex before undertaking any analysis of the residual capex forecast. However we were unable to do this for the following reasons:

- The forecast major project capex shown in the templates did not reconcile with the major project capex derived from aggregating the forecast capex shown in each of the major capex sheets. This is shown in Table 2.3 below.

**Table 2.3: Discrepancies in Forecast Major Project Capex (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application					
Template	19.33	117.44	34.81	57.81	79.57
Aggregated Project Sheets	23.59	121.46	39.57	62.66	88.94
Resubmission After Clarificatory Meeting					
Template	24.49	128.74	43.18	70.17	105.05
Aggregated Project Sheets	24.02	121.74	39.44	61.97	89.73

- The historic expenditure provided after the clarificatory meeting for the line loss management program included both materials and labor but the historic expenditure for the other three projects appeared to provide for materials only.
- We were not satisfied that there was no overlap between the reported historic expenditure on the Line Loss Management Program and that on the Transformer Replacements and Retrofits, since both projects involve the replacement of transformers in existing locations. Also it was not clear to us that the reported historic expenditure appropriately provided for the installation of used transformers in a new location.

We have had been unable to fully resolve these issues so for this analysis we have treated the above four quality improvement projects as residual capex. We have incorporated this change into a recategorized forecast capex to serve as the baseline for this review and which we derived in the following manner.

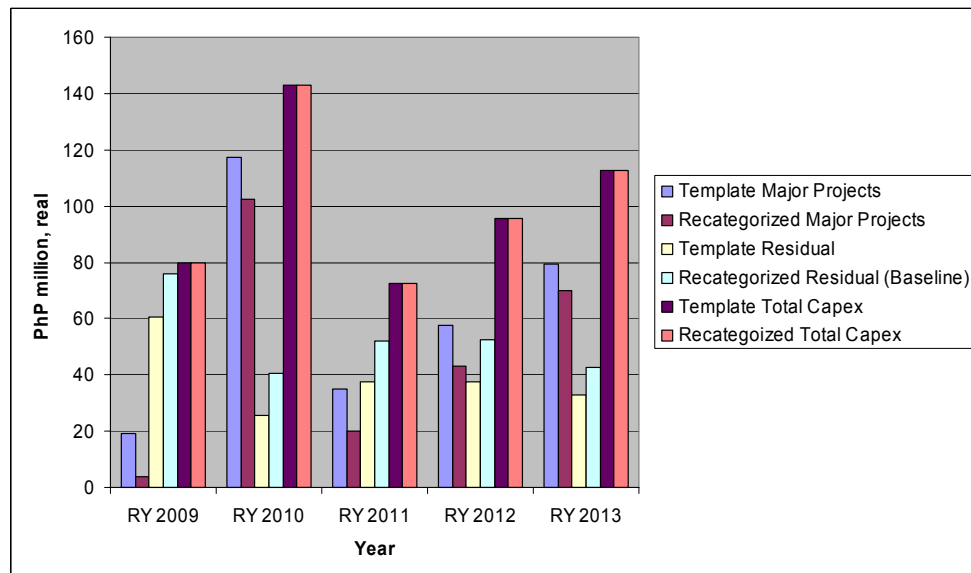
- The recategorized total capex forecast was taken to be the total capex shown in the capex template submitted with the revenue application.
- The recategorized major project forecast was derived by aggregating the expenditures in the major project sheets, excluding the four project sheets for the quality improvement initiatives identified above.
- The difference between the total capex forecast and the derived major project forecast was taken to be the baseline residual capex forecast.

This analysis is shown in Table 2.4. A comparison between the template forecast and the recategorized forecast used as the baseline for this review is shown in Figure 2.6.

**Table 2.4: Derivation of Revised Baseline Residual Capex (PhP million, real 2008)**

	<b>RY 2009</b>	<b>RY 2010</b>	<b>RY 2011</b>	<b>RY 2012</b>	<b>RY 2013</b>
Revenue Application Total Capex	79.86	142.94	72.33	95.57	112.58
Aggregated One-off Projects	3.94	102.48	20.13	43.00	69.85
<b>Baseline Residual Capex</b>	<b>75.92</b>	<b>40.46</b>	<b>52.20</b>	<b>52.57</b>	<b>42.73</b>
Revenue Application Residual Capex	60.52	25.50	37.52	37.76	33.01
Baseline Adjustment	15.40	14.96	14.68	14.81	9.72

**Figure 2.6: Comparison of Template and Recategorized Baseline Forecasts (PhP million, real 2008)**



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## 2.5 REVIEW OF MAJOR PROJECTS

### 2.5.1 Luinab 20/25 MVA Substation

This project involves the construction of a new 20/25 MVA, 69/13.8 kV substation at Barangay Luinab on land currently owned by ILPI. The new substation is located close to the TransCo 69 kV line and the project includes the construction of a 250 metre 69 kV spur line to provide supply from the grid. There will be four new 13.8 kV feeders, which will interconnect with other feeders on the 13.8 kV network through normally open disconnectors. ILPI's estimated cost for this new substation is PhP 54.4 million and commissioning is planned for RY 2010.

*Comment:*

The project will have the following benefits.

- It will relieve the load on the two existing 69/13.8 kV transformers and provide additional backup capacity should one of the existing transformers fail. In our view the need for additional transformer capacity is urgent, because the existing two transformers are 80% utilized at peak load and also because of the likely condition (and consequent probability of failure) of the relatively highly loaded Pala-O unit.
- It will improve the reliability of the 13.8 kV distribution network by increasing the number of feeders and hence the average number of customers connected to each feeder. One of the major reasons for the relatively poor reliability of electricity distribution networks in the Philippines, when compared to similar networks in developed countries, is the small number of feeders and the consequent high number of customers connected to each feeder. The result is that a high proportion of a utility's customers lose supply as a consequence of each distribution feeder fault, and this has a negative impact on network reliability.

We recommend that the project proceed. In fact we would go further and suggest that the project should be completed urgently in order to secure the network against a potential failure of the Pala-O transformer. We do however suggest that two aspects of the proposed design be reviewed.

- ILPI should consider increasing the forced air rating of the transformer to 30 MVA. As a general rule we do not favour large power transformers if they carry an excessively high proportion of a utility's total load or if they limit the number of 13.8 kV feeders, as both factors tend to reduce overall distribution system reliability. However a forced air rating of 30 MVA, when combined with the available 12 MVA at Kiwalan, would provide sufficient capacity to carry the total forecast load on the network through to RY 2012. All this capacity may be needed if the Pala-O transformer should fail. Our information indicates that the additional cost of a transformer with a higher forced air rating is likely to be well under 5%, which is relatively small when compared to the extra capacity provided. On the negative side the higher rated transformer may have a slightly larger footprint due to the installation of additional or larger cooling radiators.
- ILPI should consider ways of increasing the security of the connection to the 69 kV network. It is proposed that the network be connected directly to the TransCo Agus 6 – Lugait subtransmission line by a single spur line and no alternative supply would be available should the relevant section of the TransCo line be out of service. This is in spite of the fact that ILPI has recently constructed a 69 kV tie line between Kiwalan and Pala-O substations, with the primary objective of providing an alternative connection of these substations to the 69 kV network.

It could be argued that a secure 69 kV supply is not necessary for Luinab, since in the event of a loss of incoming supply it would be possible to transfer the load to Pala-O and Kiwalan substations using 13.8 kV load transfers. However, once completed, we believe that Luinab will quickly become the major point of injection into the 13.8 kV network and that the security of its incoming supply should therefore be commensurate with that of the other two substations.

We see two ways of achieving this. From an engineering standpoint, the best solution would be to construct a second incoming connection from ILPI's existing 69 kV Pala-O-Kiwalan line. However it is not clear that a suitable route would be available. A less costly approach would be to install 69 kV disconnectors on the TransCo line each side of the tee off point. These would be normally closed but, in the event of a fault, one switch could be opened to allow supply from the end of the line remote from the fault. While the second option would still leave the incoming 250 metre 69 kV spur line vulnerable, the length of this line is short and, as the route is through an urban area, an unplanned outage is less likely.

Our recommended cost provision for this project is PhP 55.37 million. This is an increase of PhP 0.91 million over the amount provided in ILPI's revenue application to provide for the recommended additional forced air transformer rating. Cost information on PB Associates' database indicates that this provision should be adequate. This recommendation is shown in Table 2.5.

**Table 2.5: Recommended Capex for Luinab Substation (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application		54.47			
Recommendation		55.38			
Adjustment		0.91			

Our recommended capex does not provide for a higher level of incoming 69 kV security since the best way of providing this is uncertain. It will depend on a number of factors including whether the purchase of TransCo assets proceeds and whether it is feasible to build an overhead connection from the existing tie line. We therefore suggest that this work is deferred until early in the third regulatory period.

### 2.5.2 Zamora 5 MVA Substation

The project involves the construction of a new 5 MVA substation on land already owned by ILPI within the Iligan downtown area. The substation will have a single feeder and will supply the Iligan central business district. The project includes the construction of a 400 metre 69 kV spur line that will connect the new substation to ILPI's Kiwalan-Pala-O tie-line circuit.

ILPI sees this substation as replacing the 5 MVA point of connection at Overton. As it will use a "semi-retired" transformer that is already available and owned by ILPI, it is seen as a cost effective option for providing additional 69/13.8 kV transformation capacity. The estimated cost is PhP 14.4 million and commissioning is planned for RY 2011.

#### *Comment*

The project will have the following benefits.

- It will relieve the load on the two existing 69/13.8 kV transformers and provide additional backup capacity should one of the existing transformers fail. In our view the need for additional power transformer capacity is urgent, given that the existing two transformers are 80% utilized at peak load and also because of the likely condition (and consequent probability of failure) of the Pala-O unit.

- It will improve the reliability of the 13.8 kV distribution network by increasing the number of feeders and hence the average number of customers connected to each feeder. One of the major reasons for the relatively poor reliability of electricity distribution networks in the Philippines, when compared to similar networks in more developed countries, is the small number of feeders and the consequent high number of customers connected to each feeder. The result is that a high proportion of a utility's customers lose supply as a consequence of each distribution feeder fault, and this has a negative impact on network reliability.

However we are concerned that the proposed 5 MVA additional transformer capacity is insufficient to adequately address what seems to be the most serious weakness in ILPI's existing network, namely the age and risk of a failure of the Pala-O transformer.

With the proposed new Luinab and Zamora substations in service, ILPI would have a total of 79 MVA of transformer capacity in service (assuming the forced air rating of the new Luinab transformer is increased to 30 MVA). However, should the Pala-O transformer fail, this would be reduced to 47 MVA increasing to 52 MVA once the 5 MVA standby transformer at Pala-O is put in service. Our demand projections indicate that the 47 MVA peak demand will be reached by 2016 and the 52 MVA demand by 2020. ILPI's forecast demand would suggest that these loads would be reached sooner.

We also believe that there is a risk in relying on the 5 MVA transformers, which were manufactured in 1977 and which have not been connected to the network for some time. While it is planned to refurbish the Zamora transformer before it is recommissioned, there is a possibility that during this refurbishment the windings will be found to have deteriorated to the extent that repair is uneconomic. There is also a risk that once returned to service the transformer may operate satisfactorily at low loads but fail prematurely if operated at close to its rated load. These comments apply equally to the standby Pala-O transformer.

We therefore recommend that this project not proceed and that the expenditure be reallocated to accelerate the replacement of the Pala-O transformer. This is discussed further in Section 2.5.6. The capex adjustment resulting from this recommendation is shown in Table 2.6.

**Table 2.6: Recommended Capex for Zamora Substation (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application			14.44		
Recommendation			-		
Adjustment			(14.44)		

### 2.5.3 Acquisition of TransCo Subtransmission Assets

ILPI's capex forecast proposes a total expenditure of PhP 75.13 million in the second regulatory period for the purchase of TransCo 69 kV subtransmission assets. The expenditure proposed is in accordance with Table 2.7.

**Table 2.7: Forecast Expenditure for Purchase of TransCo Subtransmission Assets (PhP million, real 2008)**

RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
	37.96		28.13	9.04

*Comment:*

- Section 8 of the Electric Power Industry Reform Act 2001 (EPIRA) requires subtransmission assets to be segregated from the transmission assets and requires TransCo to sell these assets to qualified distribution utilities. It further provides that the disposal value of the assets is based on their revenue potential.
- ERC has issued guidelines for the sale and transfer of subtransmission assets pursuant to Section 8 of EPIRA<sup>9</sup> (Subtransmission Guidelines). Article III of these Subtransmission Guidelines sets out criteria to distinguish transmission assets from subtransmission assets and requires that, to be classified a subtransmission asset, a line must:
  - be radial;
  - directly connect an end-user or group of end-users to the grid; and
  - be exclusively dedicated to the service of that end-user or group of end-users.
- The lines that ILPI is proposing to buy are not radial but interconnect TransCo's Agus 6 and Lugait substations. A cursory review of the Subtransmission Guidelines would indicate that ILPI is therefore not entitled to buy these assets. ILPI, however, is arguing that, notwithstanding the fact that the lines are not radial, they are exclusively used to supply its own network and directly connected customers located within its franchise area, whom ILPI is entitled to supply under the terms of its franchise<sup>10</sup>. We consider this a reasonable argument provided that the operation of the transmission network is not affected by the sale of the assets. In our view the test for this should be that TransCo would still be able to provide a service to other grid users in full compliance with the Grid Code if the sold assets were not connected to the grid. We have insufficient information to assess this but note that TransCo has, arguably, conceded this point by agreeing in principle to sell the assets to ILPI. If TransCo is indeed able to meet the above Grid Code compliance test, there appears to be no good reason for ERC not to allow the sale to proceed, notwithstanding fact that the lines are not radial.
- ILPI has provided a copy of a Contract to Sell between it and TransCo for the sale of the assets. This contract has still to be signed but we understand from ILPI that the terms have been generally agreed by both parties. The contract will need to be approved by ERC before the sale can be finalized. The contract copy provided to us did not include Annex F, which describes the assets in detail and the basis for the contract price. We understand that the contract covers only those assets that ILPI proposes to purchase in 2009 and note that there was a difference in the selling price (which was subject to further adjustments to cover the cost of improvements not yet recognized or included in the TransCo accounts) in the Contract to Sell and the purchase price provided by ILPI in its revenue application. We were not provided with a reconciliation to explain this difference<sup>11</sup>.
- We understand that the assets are classified by TransCo as either connection or residual subtransmission assets for pricing purposes. This means that the price paid by ILPI or directly connected customers to TransCo for the use of the assets is based on the value of the assets. It is therefore possible to directly assess the

<sup>9</sup> Guidelines to the Sale and Transfer of the TransCo's Subtransmission Assets and the Franchising of Qualified Consortiums, Energy Regulatory Commission, October 17 2003.

<sup>10</sup> When open access is declared in accordance with Section 31 of EPIRA this will not apply in respect of electricity supply. However, it will continue to apply in respect of the provision of electricity distribution services.

<sup>11</sup> The selling price in the contract to sell was PhP 57.57 million whereas the purchase price in the revenue application was PhP 37.96 million (real, 2008).

impact of the sale on ILPI's subtransmission costs. ILPI has provided PB Associates with an analysis that shows a gross monthly benefit from the purchase of the first tranche of assets in 2009 to be PhP 414 thousand, based on the charges approved by ERC in its decision of 7 December 2007 on ERC case 2007-007. These benefits arise from ILPI's own avoided transmission costs (PhP 202 thousand) and the transmission connection charges paid by directly connected customers (PhP 212 thousand)<sup>12</sup>.

- The assets proposed for acquisition in RY 2012 and RY 2013 comprise switch bays in the Agus 6 and Lugait substations. We note that line terminations in the Agus 6 switch bays are configured in a breaker-and-a-half arrangement, which means the assets are shared with the line connected to the opposite side of the relevant switchyard diameter. From a network operation perspective, the benefits of ILPI acquiring these shared assets are not clear.

Having considered the above issues we have concluded that the forecast cost of procuring subtransmission assets from TransCo should not be (and need not be) taken into account in determining ILPI's allowed revenue for the second regulatory period. The compelling reason for this is that any delay in executing the Contract to Sell will result in a windfall gain for ILPI, since funding for the purchase of the assets would not be needed until the transaction was completed. Over the period of any delay, customers would effectively be paying twice for the use of these assets – through the transmission component of the unbundled rate and also through the distribution wheeling rate. Under clause 12.2 of the RDWR, any delay would not trigger a reopening of the revenue determination until its length had exceeded 18 months.

We are also concerned that inclusion of the forecast purchase costs of these assets in the allowed revenue used to determine the MAP would prejudice the ERC's own review of the Contract to Sell. It will be more difficult for the ERC to refuse approval of the contract knowing that the purchase cost is already included in the allowed revenue and that any delay in finalising the transaction could result in a windfall gain for ILPI at the expense of its customers. However, the ERC's decision as to whether or not it should approve the acquisition of the assets will necessarily involve consideration of issues that are outside the scope of this expenditure review.

Furthermore we do not see any need for the forecast purchase cost of subtransmission assets to be included in the allowed revenue. As noted above, the purchase of subtransmission assets will provide benefits to ILPI in the form of avoided connection charges and payments from directly connected customers. We submit that these benefits, which do not accrue until any sale is executed, should be used to fund the purchase. This approach could involve setting the purchase cost on the basis of the net benefit of the purchase to ILPI as calculated from a discounted cash flow analysis. Such an analysis could assess the benefits on the basis of ERC's currently approved connection charges and the costs on the basis of forecast operating, maintenance and refurbishment costs. Such an approach is consistent with Section 8 of EPIRA, which states:

*The TransCo shall determine the disposal value of the subtransmission assets based on the revenue potential of such assets.*

The approach is also consistent with Article V, Section 2 of the Subtransmission Guidelines. Should the Commission decide to adopt such an approach we see two further issues that need to be resolved.

- In order for this approach to work, ILPI will need to retain the avoided transmission charges as these will be needed to fund the purchase and any

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<sup>12</sup> The transmission connection charges of directly connected customers would be paid to ILPI once the ownership of the assets was transferred.

subsequent maintenance. Technically this would involve reducing ILPI's transmission connection charges and increasing its distribution wheeling rates. However, if the purchase cost has been correctly set, there should be no net impact on the total cost of electricity to customers<sup>13</sup>. Nevertheless, under the unbundled rate structure it will be necessary for ERC to authorise the increase in the distribution wheeling rate. If this cannot be done as part of the ERC's approval of the Contract to Sell it may be necessary to adjust the X factor in accordance with clause 12.4 of the RDWR.

- We see this adjustment to be an interim step that would adjust the MAP applied to ILPI's current customers for the remainder of the regulatory period during which the assets were purchased. At the reset for the following regulatory period, the value of the purchased assets would be rolled into the regulatory asset base (RAB) and costs associated with refurbishing, operating and maintaining the assets would be included in the expenditure forecast. At that time, revised distribution charges to those individual customers directly connected to the purchased lines would also be determined.

On the basis of the above considerations we recommend that no provision for the purchase of TransCo subtransmission assets be included in the allowed capex. The capex adjustments resulting from this recommendation are shown in Table 2.8.

**Table 2.8: Recommended Capex for Purchase of Subtransmission Assets (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application		37.96		28.13	9.04
Recommendation		-		-	-
Adjustment		(37.96)		(28.13)	(9.04)

#### 2.5.4 ILPI 69 kV Tie Lines

In 2007 ILPI completed the construction of a 69 kV interconnector between its Pala-O and Kiwanan substations. This interconnection provides a second 69 kV incoming supply line to both substations and allows ILPI's current total load to be fully supplied in the event that supply is not available at one of the two 69 kV TransCo metering points. This tie-line project, as described in ILPI's revenue application, would construct an additional 11.89 circuit kilometre of line along the national highway to extend the line toward the two supply sources, the Agus 6 and Lugait switchyards. The forecast cost of this project is PhP 30.68 million with PhP 14.86 million to be spent in RY 2012 and PhP 15.82 million to be spent in RY 2013.

ILPI states that the project is aimed at providing flexibility and interconnectivity between its substations and the supply sources. As the line will be constructed along the national highway it will be more accessible than the current TransCo owned line, permitting more rapid fault finding and faster restoration times.

The revenue application also states:

*The transferred subtransmission lines also traverse private lands that do not have documented right of way grants. Landowners are said to be lying in wait for the take-over of the private utility to file claims for compensation which they are unable to get from government-owned TransCo. Non-implementation of the project along the*

<sup>13</sup> This analysis would be part of ERC's decision on whether or not to approve the contract. A further benefit of treating the purchase of TransCo assets separately from the implementation of PBR is that it allows the impact of the transaction on electricity prices to be analysed independently of other rate setting issues.

*highway will make system reliability hostage to the landowners as they can refuse entry to the maintenance crew who will need to make repairs or maintenance on the lines. Compromise payments to landowners to alleviate such pressure might turn out expensive on the part of ILPI, burdening its customers to whom the cost will be charged. Otherwise, ILPI's system reliability will deteriorate if such situations remain unresolved.*

*Comment:*

- There are apparent discrepancies between the information submitted in the revenue application and the information submitted by ILPI following the clarificatory meeting. These include:
  - The diagram on page 49, schedule C1.4 of the revenue application shows the proposed Luinab substation being connected to the Kiwalan-Pala-O tie line. However the Luinab project sheet shows this substation being connected to the existing TransCo line and makes no provision for a connection to the tie line. This latter arrangement is supported by the single line diagrams submitted following the clarificatory meeting. We question the rationale for connecting the Luinab substation, which as noted in Section 2.5.1 is likely to become the main source of supply to ILPI's 13.8 kV distribution network in the short term, only to the TransCo line if its potential reliability is as poor as indicated in the project sheet.
  - The project sheet indicates that one of the proposed new tie lines will be terminated at the Agus 6 switchyard and we assume that the project cost has been assessed on this basis. However information submitted following the clarificatory meeting shows the new tie line being terminated at Treasure Steel and an existing Agus 6 – Treasure Steel line being used to complete the connection. The distance involved appears significantly shorter and this could reduce the cost of this section of the project.
  - There are discrepancies in the information provided regarding the proposed termination of the northern tie line. The map shows this line being terminated at the Lugait substation switchyard while the single line diagrams show the termination at Mapalad. The exact termination point will have a significant impact on the cost of the project since the line length between Mapalad and Lugait is about 3.4 km.
- The comments above on the reliability of the existing TransCo line are emotive and as such do not provide a compelling argument for the project. If the potential problems are as serious as indicated in the above extract from the project sheet, we question the wisdom of ILPI buying the line off TransCo. It might be better to leave the line in TransCo's ownership if ILPI really thinks the potential problems will materialize.
- Completion of the project will give a level of reliability in excess of the n-1 degree of security for subtransmission networks permitted by Table D1 of the RDWR. The tie line between the Kiwalan and Pala-O substations provides an alternative incoming supply to each substation. Both these incoming supplies are currently connected to the TransCo Agus 6-Lugait line, which in turn can be supplied from either end. Hence n-1 security (after switching) is achieved with the existing arrangement.

On the basis of the above considerations we recommend that this project not proceed at this time. Reinforcement of the existing network should be undertaken when it is established that one of the existing 69 kV line sections will be overloaded following an n-1 contingency event and no evidence has been provided that this will occur before the end of the second regulatory period.

The capex adjustments resulting from the above recommendation are shown in Table 2.9.

**Table 2.9: Recommended Capex for 69 kV Tie Lines (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application				14.86	15.82
Recommendation				-	-
Adjustment				(14.86)	(15.82)

### 2.5.5 Kiwalan Switching Station

ILPI is proposing to construct a 66 kV switching station in the Kiwalan industrial area to provide individual 69 kV supply line protection to the Kiwalan substation, ILPI's existing two directly connected 69 kV customers and the three additional directly connected bulk customers in the areas that are presently directly connected to the TransCo 69 kV line. The project will include the acquisition of land, construction of the necessary civil works and control building, the installation of four new 69 kV circuit breakers, complete with support structures and busbars, disconnect switches, protection devices and other associated equipment. It will also be necessary to divert the lines supplying the existing and new customers, as well as the line feeding Kiwalan substation into the new switchyard.

The forecast project cost is PhP 37.81 million which is expected to be incurred in RY 2013.

*Comment:*

- The project appears contingent on the purchase of the TransCo subtransmission assets and would seem to be designed to mitigate any concerns the newly acquired direct connected customers may have regarding ILPI's purchase of these lines. Essentially the project involves the provision of connection assets which, if the project proceeds, would be paid for through the distribution wheeling rate by ILPI's existing customers rather than by the industrial customers that will use the assets.
- ILPI's justification for the project relies on the fact that the existing connections do not comply with clause 5.5.1.2 of the Grid Code, which requires a connection point to be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the point of connection. However we believe that this requirement should apply only to new connections and the arrangements at existing connection points should be grandfathered. We also note that, once ILPI has purchased the TransCo assets, the Grid Code will cease to apply and there is no corresponding requirement in the Distribution Code.
- We do not follow the logic of ILPI's statement in the in Schedule C1.54 Page 64 of the revenue application. It argues that *the project is needed to improve reliability especially for customers connected to 69 kV* and further that *new bulk power loads will be affected by ILPI's existing reliability level*. We do not believe that the new bulk customers will be adversely affected by ILPI's existing reliability level as these direct connected customers are already protected against faults on ILPI's 13.8 kV distribution network by the incoming 69 kV and 13.8 kV circuit breakers at ILPI's power substations.
- ERC has advised PB Associates that its policy is that, when a utility purchases TransCo subtransmission assets that also supply direct connected customers, the assets used to supply the direct connected customer should not be included in the regulatory asset base for the purposes of establishing the allowed revenue.

Where purchased subtransmission assets are shared between direct connected and utility customers, the value of the shared assets is to be apportioned in accordance with the relative peak demands. If this project was to proceed it would be logical for its costs to be apportioned in a similar manner. However such a requirement would be likely to prevent the project proceeding unless the directly connected customers voluntarily agreed to pay their share. We suspect that such agreement is unlikely.

We therefore recommend that the cost of this project not be included in ILPI's allowed revenue. We support the concept of increasing the number of circuit breakers on the 69 kV network but consider a smaller number of circuit breakers placed at more strategic locations would be more cost effective. For example, if two circuit breakers were placed on the 69 kV line to be acquired from TransCo at either side of the new Luinab tapping point, the protection could be designed to ensure that any fault on the 69 kV lines would generally only affect either the Kiwalan or Pala-O substations<sup>14</sup>. A remotely controlled switch on the existing ILPI tie line could then be used to rapidly restore supply to the affected substation.

The capex adjustment resulting from the above recommendation is shown in Table 2.10.

**Table 2.10: Recommended Capex for Kiwalan Switching Station (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application					37.81
Recommendation					-
Adjustment					(37.81)

### 2.5.6 Power Substation Rehabilitation

The forecast capex on this project provides for the refurbishment of the Kiwalan and Pala-O substations. The planned work includes the refurbishment of both transformers including the replacement of the high voltage bushings and refilling of the transformers with new mineral oil. At Kiwalan substation it is planned to install new potential transformers on the high voltage side, a new 15 kV circuit breaker<sup>15</sup> and replace the existing differential protection relays and surge arrestors. At Pala-O substation the planned work includes the installation of new high and low voltage circuit breakers<sup>16</sup>, replacement of the battery bank, one 69 kV disconnect switch and the installation of a new differential protection relay.

The estimated cost of this work is PhP 13.99 million with expenditure programmed as shown in Table 2.11. We assume that the expenditure in RY 2009 is for the Kiwalan substation and expenditure in RY 2010 is for Pala-O.

**Table 2.11: Forecast Cost of Power Substation Rehabilitation (PhP million, real 2008)**

RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
3.94	10.05			

<sup>14</sup> With this arrangement it is also possible to lose supply to the Luinab substation, which does not have a backup 69 kV supply. However the probability of this is low because of the short distance between the two circuit breakers.

<sup>15</sup> We assume this is the incoming circuit breaker on the low voltage side.

<sup>16</sup> ILPI has already purchased the high voltage circuit breaker but this has still to be installed.

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*Comment*

- The work plan shows a strong emphasis on updating the protection systems at both substations with the replacement of three of the four transformer circuit breakers and the differential protection relays at both sites.
- We have reviewed the asset valuation data on the equipment at both substations and note that the Kiwalan substation was first commissioned in 1998. All assets currently in service were first commissioned less than ten years ago. Given the expected life of the equipment and the relatively moderate loading of the substation we would not expect a major transformer refurbishment to be necessary at this time. ILPI has provided insufficient evidence in its revenue application as to why all the work proposed is necessary. For example we would be surprised if a ten year old transformer required its oil to be completely replaced with new oil and the problem with the differential protection may be due simply to an incorrect protection setting.
- The situation at Pala-O is different since the load on this substation is high and much of the equipment, including the transformer, is nearing the end of its useful life. Given the importance of Pala-O to the security of the network, we think a more aggressive refurbishment, including the replacement of the transformer, is justified.
- We are concerned at ILPI's proposal to take the Kiwalan transformer out of service before the new Luinab substation is commissioned, as this will mean potentially loading the high-risk Pala-O transformer up to its full rated capacity for the period of the outage. We consider that it would be more prudent to defer the refurbishment of this substation until after the Luinab substation has been commissioned and for this reason we have delayed the timing of the expenditure.

We recommend not only that the proposed expenditure be allowed but also that the provision be increased to allow for the replacement of the Pala-O transformer. We understand that the switchyard at Pala-O is small and consider that it may be desirable to increase the size of this compound and rearrange some of the equipment. This should be possible as the switchyard occupies only a part of the site.

In assessing the cost that should be allowed for this work we have assumed the installation of a new 20/30 MVA transformer similar to the transformer recommended for Luinab. If this proposal is adopted, by the end of the second regulatory period the 13.8 kV network will be supplied by two new 20/30 MVA transformers and the existing 10/12 MVA transformer at Kiwalan. This should provide sufficient power transformer capacity to meet expected growth in the medium term with n-1 security.

While we recommend that the full requested expenditure on Kiwalan be allowed, it may be that some of the work that ILPI is planning to undertake at this substation could be more effectively utilized at Pala-O or elsewhere on the network. Therefore, we suggest that ILPI employ an experienced external contractor to assess the condition of the equipment at Kiwalan substation through non-destructive testing, before commencing the refurbishment work proposed for this site.

Our recommended capex provision is shown in Table 2.12. We have added in a provision of PhP 23.72 million for the replacement transformer. In order to derive this we noted that the standard procurement cost for a 20 MVA transformer for the second entry point asset valuations was PhP 17.26 million, and the total installation overhead was 15%. The procurement cost used by ILPI for the Luinab price estimate was PhP 18.24 million, a difference of 5.5%. This is reasonable once inflation has been allowed for. We have inflated this cost by 30% to cover the additional cooling (5%), standard installation cost (15%) and additional installation costs (10%) to cover potential costs arising from the need to install the new transformer around existing infrastructure on a congested site. We do not see the additional work implied in this recommendation as delaying or

preventing the purchase of TransCo's 69 kV lines, should this be approved by ERC, since such a purchase should be largely self-funding.

**Table 2.12: Recommended Provision for Power Substation Rehabilitation (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application	3.94	10.05			
Recommendation			33.77	3.94	
Adjustment	(3.94)	(10.05)	33.77	3.94	

### 2.5.7 Rehabilitation of Acquired TransCo Subtransmission Assets

A joint survey of the 69 kV subtransmission lines to be acquired from TransCo was undertaken by TransCo and Commission on Audit inspectors in 2002. This identified a number of assets requiring replacement. Those assets that were deemed to require immediate attention have already been replaced by TransCo but those that were deemed to have more than five years remaining life have still to be replaced. As five years have elapsed since the survey this work is now considered a high priority.

The forecast cost of this work is shown in Table 2.13 below.

**Table 2.13: Forecast Cost of TransCo Subtransmission Asset Rehabilitation (PhP million, real 2008)**

RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
		5.69		7.18

#### *Comment*

- This project is conditional on the acquisition of the TransCo assets actually proceeding. Since we have recommended in Section 2.5.3 that this issue be considered separately from this expenditure review, this project should also be considered separately. This does not suggest that we consider that the work is not necessary or that it should not proceed in the event that the purchase of the assets goes ahead. However it may be appropriate to defer this work until the third regulatory period.
- The ERC position that the cost of the purchase of TransCo assets be shared between the different users in proportion to their peak demands complicates the treatment of this project. If the purchase cost of the assets is to be shared then it is logical for the cost of this upgrade project to be shared in a similar manner. ILPI's revenue application does not provide for this.
- The fact that some components have deteriorated to the extent that they require replacement should impact the value of the assets and hence their purchase cost. This would be appropriately accounted for if the purchase cost was set on the basis of a discounted cash flow analysis and the cost of this project was included in the analysis.

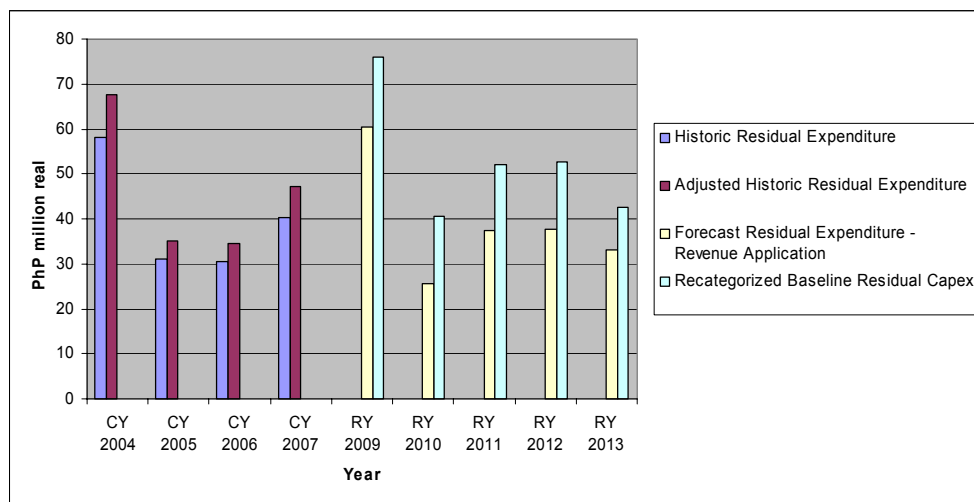
On the basis of the above considerations we recommend that no provision for the rehabilitation of TransCo subtransmission assets be included in the allowed capex. The impact of this recommendation on the forecast capex is shown in Table 2.15.

**Table 2.14: Recommended Provision for TransCo Subtransmission Asset Rehabilitation (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Revenue Application			5.69		7.18
Recommendation			-		-
Adjustment			(5.69)		(7.18)

## 2.6 REVIEW OF RESIDUAL CAPITAL EXPENDITURE

ILPI's historic and forecast residual capex is shown in Figure 2.7

**Figure 2.7: Historic and Forecast Residual Capex (PhP million real 2008)**

The reason for developing a recategorized baseline residual capex is discussed in Section 2.4. It includes the cost of ILPI's discretionary initiatives to reduce losses and improve the performance of its medium and low voltage networks and for which separate project sheets have been submitted in the revenue application. We have reviewed the justification provided by ILPI for this reliability improvement expenditure and believe it is justified and well targeted. We therefore do not intend to recommend a level of residual capex that is insufficient to fund the continuation of these initiatives at current real expenditure levels. As the adjusted historic residual capex also includes the cost of these initiatives a comparison between the adjusted historic residual capex and the recategorized baseline is valid and this comparison forms the basis for our analysis.

A feature of Figure 2.7 is the relatively high levels of historic residual capex in CY 2004 and CY 2007 and the forecast high level in RY 2009. While ILPI has not provided any explanation for the levels of expenditure in the historic years we can make the following comments.

- The high level of residual capex in CY 2004 was due to a high level of renewal capex. Expenditure on poles towers and structures, overhead conductors and devices and distribution transformers was between two and four times the level in the following two years. We assume that this is due to the completion of a one-off major project, and therefore, in using the historic capex as a basis for forecasting the appropriate level of underlying residual capex, we have reduced the real capex in CY 2004 to the average level of residual capex over the following two years.

- The high level of residual capex in CY 2007 was due to the high costs of pole renewals and high growth related expenditures on poles and conductors. We know that the 69 kV tie-line was constructed over this time and note that this capex has not been separately reported as a major project. The categories of additional expenditure are consistent with the construction of a new 69 kV line in an urban area where it is necessary to work around existing electricity distribution infrastructure. To allow for this we have reduced the level of expenditure to the average level of residual capex over the previous two years for comparative purposes.
- The forecast high level of residual capex in RY 2009 is due to growth related expenditure on vehicles, IT equipment and miscellaneous equipment. ILPI has submitted a document that breaks down its residual capex into individual projects and expenditures. We have not examined these smaller projects and expenditures individually as we do not have sufficient information to assess the merit of each on a case by case basis. We would however expect such a document to identify and justify major expenditure items, particularly in situations where the expenditure resulted in significant deviations from historic and forecast trends. This document gives explanations for the high residual expenditure on vehicles and IT equipment in 2009 but provides no explanation for the high level of expenditure on miscellaneous expenditure. Of the PhP 6.00 million growth related residual capex on miscellaneous equipment in RY 2009, only PhP 0.50 million is explained. The additional expenditure on vehicles and IT equipment seems reasonable.

On this basis we recommend that the residual capex forecast by ILPI for RY 2009 be reduced by the unexplained PhP 5.50 million and that residual capex in years RY 2010-13 be set at the average adjusted historic residual capex over RY 2005-06, namely PhP 34.85 million per annum. It could be argued that the approach we have used to determine the recommended residual capex to be allowed over the period RY 2010-13 is not particularly rigorous. We accept this but consider that we have little choice but to base our recommendation on such high level assumptions, given the inconsistencies in the information provided to us. We also note that a significant amount of the residual reliability improvement expenditure for which major capex sheets were provided is discretionary and this provides ILPI with some ability to reallocate this expenditure to less discretionary line items should this prove necessary.

On this basis the recommended forecast residual capex for RY 2009-13 is shown in Table 2.15 below.

**Table 2.15: Recommended Residual Capex RY 2009-2013 (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Recategorized Baseline Residual Capex	75.92	40.46	52.20	52.57	42.73
Recommendation	70.41	34.85	34.85	34.85	34.85
Adjustment	(5.50)	(5.61)	(17.35)	(17.72)	(7.88)

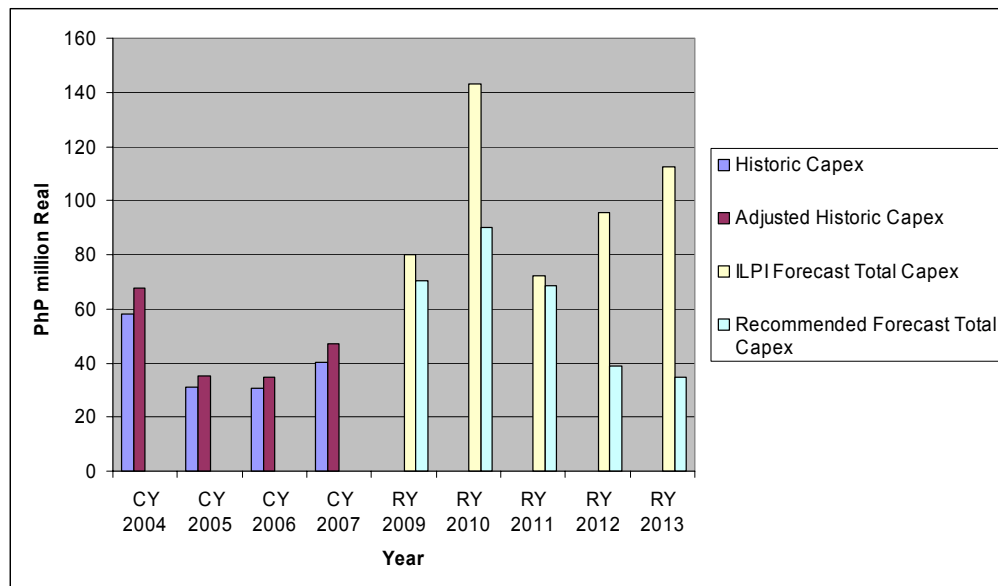
## 2.7 SUMMARY OF RECOMMENDED CAPITAL EXPENDITURE

On the basis of the above discussion we recommend the capex shown in Table 2.16 below be allowed for the period RY 2009-13.

**Table 2.16: Recommended Capex RY 2009-13 (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
<b>Forecast Capex (Revenue Application)</b>	<b>79.86</b>	<b>142.94</b>	<b>72.33</b>	<b>95.57</b>	<b>112.58</b>
Recommended Adjustments					
Luinab Substation Transformer Capacity		0.91			
Deletion of Zamora Substation			(14.44)		
Deletion of TransCo Asset Purchase		(37.96)		(28.13)	(9.04)
Deletion of 69 kV Tie Lines				(14.86)	(15.82)
Deletion of Kiwalan Switching Station					(37.81)
Rehabilitation of Power Substations	(3.94)	(10.05)	33.77	3.94	
Deletion of TransCo Asset Rehabilitations			(5.69)		(7.18)
Residual Capex Adjustment	(5.50)	(5.61)	(17.35)	(17.72)	(7.88)
<b>Recommended Capex</b>	<b>70.42</b>	<b>90.23</b>	<b>68.62</b>	<b>38.80</b>	<b>34.85</b>

The impact of these adjustments is shown graphically in Figure 2.8 below.

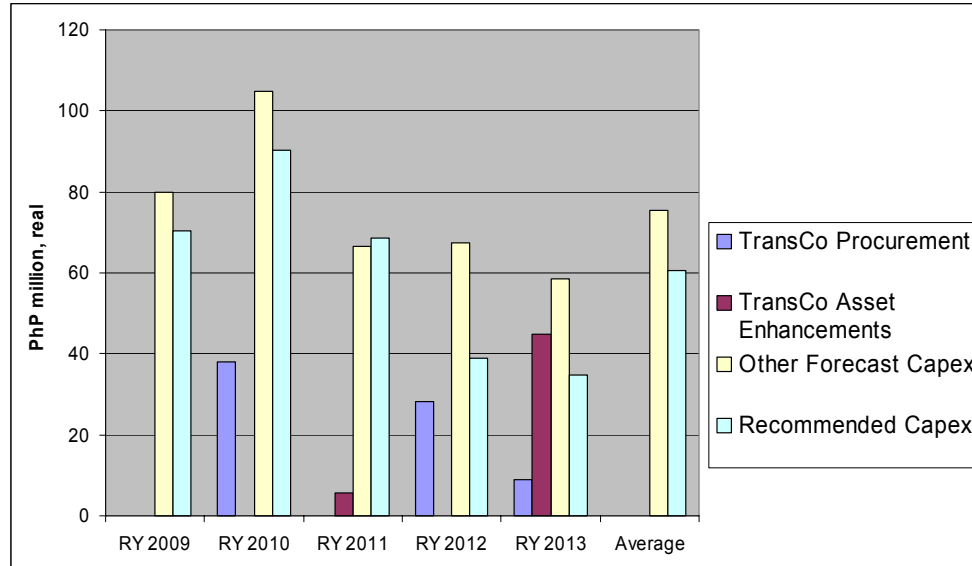
**Figure 2.8: Recommended Capex RY2009-13 (PhP million, real 2008)**

In Figure 2.9 we have separated out ILPI's forecast capex into the three categories shown below and compared our recommended capex with the different categories of forecast capex.

- *TransCo Procurement.* This is the cost of purchasing the assets from TransCo. We have recommended that this be disallowed.
- *TransCo Asset Enhancement.* These projects are contingent on the purchase of the TransCo assets and include the TransCo line refurbishment and the Kiwalan switching station. We have recommended that these projects be disallowed.
- *Other Forecast Capex.* This capex includes both residual and major project capex related to Transco's existing asset base. All our recommended capex falls into this category.

Figure 2.9 also compares the average annual “other” capex over the forecast period with the average forecast capex and shows that our recommended capex on the existing asset base is 20% lower than the ILPI forecast, notwithstanding the reallocation of funds for the replacement of the Pala-O transformer. This reallocation is the reason for the recommended higher than forecast capex in RY 2011.

**Figure 2.9: Comparison of Recommended Capex with ILPI’s Disaggregated Forecast (PhP million, real 2008)**



### 3. OPERATIONS AND MAINTENANCE EXPENDITURE

#### 3.1 ILPI'S HISTORICAL OPERATIONAL EXPENDITURE

ILPI's historical total opex in nominal Philippine PhP is shown in Table 3.1.

**Table 3.1: Historical Total Opex (PhP million, nominal)**

Operational Expenditure Category	CY 2004	CY 2005	CY 2006	CY 2007
Distribution and Connection Services Operation and Maintenance	34.20	27.55	35.31	36.28
Regulated Retail Services	13.39	22.90	19.00	21.52
Administrative and General	37.10	41.55	47.80	46.21
<b>Total Operational &amp; Maintenance Expenditure</b>	<b>84.69</b>	<b>92.00</b>	<b>102.10</b>	<b>104.01</b>

Source: ILPI Application, May 2008

The data indicates an average escalation of 7.2% per annum in nominal opex over the period CY 2004-07, with an increase of 4.0% per annum in customer numbers over the same period.

Since the historic opex reported by ILPI and shown in Table 3.1 is expressed in nominal PhP, it includes the impact of inflation. A better assessment of the relative expenditure from year to year can be obtained if historic opex is expressed in real 2008 PhP, using historical inflation indicators. Table 3.2, shows historical opex in real 2008 PhP.

**Table 3.2: Historic Total Opex (PhP million, real 2008)**

Operational Expenditure Category	CY 2004	CY 2005	CY 2006	CY 2007
Distribution and Connection Services Operation and Maintenance	41.85	31.38	37.92	37.91
Regulated Retail Services	16.38	26.09	20.40	22.48
Administrative and General	45.40	47.33	51.33	48.28
<b>Total Operational &amp; Maintenance Expenditure</b>	<b>103.63</b>	<b>104.80</b>	<b>109.65</b>	<b>108.67</b>

Source: ILPI Application, May 2008

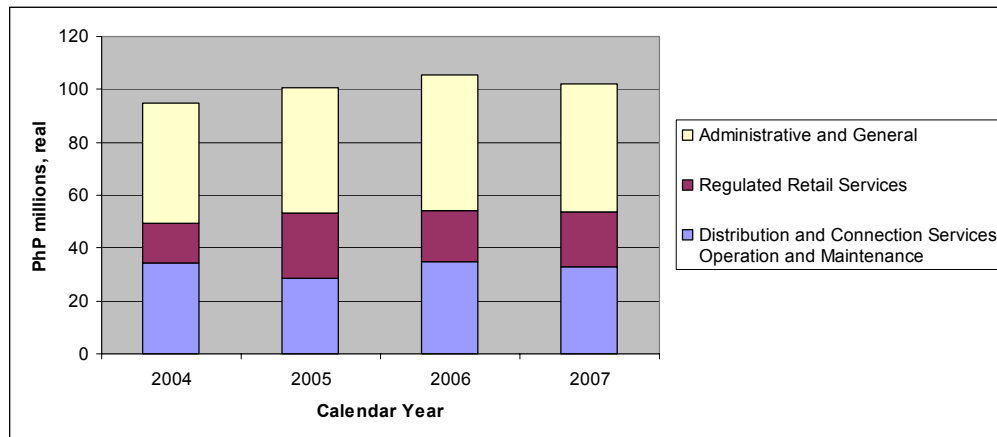
At the clarificatory meeting ILPI confirmed that, although the capex in the forecast years includes costs for both materials and installation, the capex for historic years, CY 2004-07, only includes the cost of materials. Historic installation costs are included in opex. In order to be able to validly compare the historic and future opex it was therefore necessary to make an adjustment to the historic opex by excluding these capex related installation costs. We added an installation component to each capex line item based on the installation adjustments used in the asset valuation project for the second entry group of IOUs<sup>17</sup>. Each year's historic opex was also reduced by a similar amount and the impact of this adjustment is shown in Table 3.3 below. For purposes of comparison the adjusted historical figures will be used in this report.

<sup>17</sup> See Section 2.4.

**Table 3.3: Adjusted Historic Total Opex (PhP million, real 2008)**

Operational Expenditure Category	CY 2004	CY 2005	CY 2006	CY 2007
Adjusted Distribution and Connection Services Operation and Maintenance	34.45	28.52	34.93	33.03
Adjusted Regulated Retail Services	14.96	24.86	19.43	20.62
Adjusted Administrative and General	45.40	47.33	51.33	48.28
<b>Adjusted Total Operational &amp; Maintenance Expenditure</b>	<b>94.81</b>	<b>100.71</b>	<b>105.68</b>	<b>101.93</b>
<b>Total Adjustment</b>	<b>(8.82)</b>	<b>(4.09)</b>	<b>(3.97)</b>	<b>(6.74)</b>

This adjusted historical opex, expressed in real 2008 PhP, is shown graphically in Figure 3.1.

**Figure 3.1: Adjusted Historic Opex (PhP million, real 2008)**

Source: PB Associates

Table 3.3 and Figure 3.1 demonstrate that the adjusted opex remained relatively constant over the period CY 2004-07 when measured in real PhP.

## 3.2 ILPI'S FORECASTING METHODOLOGY

Our review of the information submitted indicated that ILPI used its actual opex for CY 2007 as the base year for computing the opex budget for CY 2008 and forecast opex for RY 2009-13. It appears that the budget and forecast expenditures for each cost category were correlated with business activities, energy consumption forecasts, load growth and customer numbers. However ILPI's revenue application did not include an explanation of the correlation process nor did it provide any details of the model used to forecast each cost category.

### 3.2.1 ILPI's Forecast Opex

Budget opex for CY 2008 and opex forecasts for RY 2009-13, as included in ILPI's revenue application, are shown in Table 3.4 in real 2008 PhP. These results are also shown graphically in Figure 3.2. It should be noted that there is a nine month overlap between CY 2008 and RY 2009 so the expenditure in these two columns also overlaps.

**Table 3.4: Forecast Total Opex (Real PhP million, 2008)**

Operational Expenditure Category	CY 2008 <sup>1</sup>	RY 2009 <sup>2</sup>	RY 2010	RY 2011	RY 2012	RY 2013
Distribution and Connection Services Operation and Maintenance	30.34	35.09	37.73	39.62	41.00	42.63
Regulated Retail Services	26.52	26.76	24.81	25.01	25.67	26.40
Administrative and General	57.87	60.18	64.02	68.18	71.34	76.55
<b>Total Operational &amp; Maintenance Expenditure</b>	<b>114.73</b>	<b>122.04</b>	<b>126.56</b>	<b>132.81</b>	<b>138.01</b>	<b>145.58</b>

Source: PB Associates based on ILPI Application, May 2008

Note 1: The information is budgeted figures and for the 2008 calendar year period and adjusted for the exclusion of installation costs.

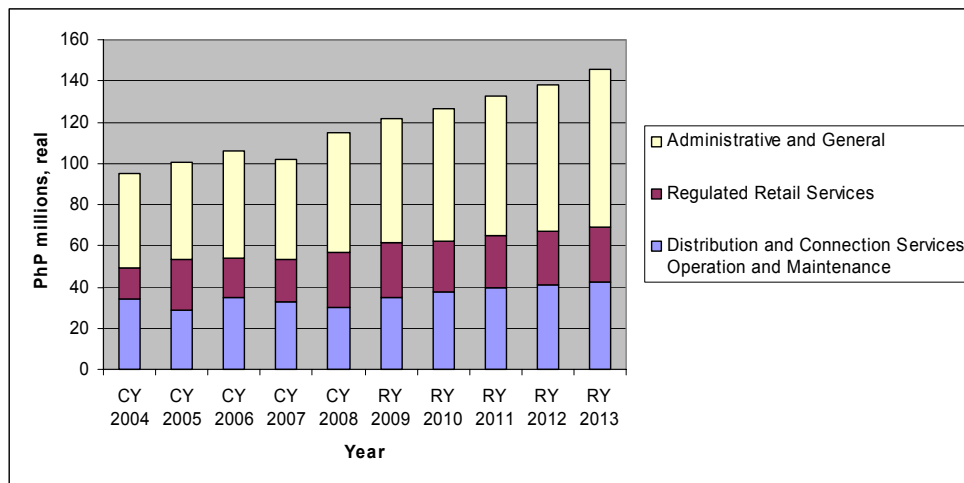
Note 2: The information is forecasted and for the 2009 regulatory year period.

**3.3 REVIEW METHODOLOGY AND ASSUMPTIONS**

Table 3.4 and Figure 3.2 show that ILPI’s forecast opex for the second regulatory period is significantly higher than the adjusted historic opex over the period CY 2004-07 in real terms. The average annual forecast opex for the second regulatory period is PhP 135.74 million, compared to an average annual expenditure of PhP 106.69 million over the four year historical period. As noted above, ILPI provided little information on the methodology that it used to forecast future opex and it is therefore not possible for us to meaningfully review the reasonableness of these increases.

Hence in order to assess the reasonableness of the ILPI opex forecasts we have used PB Associates’ opex forecasting model to derive what we consider a realistic level of opex for each year in the forecast period. The forecasts calculated from PB Associates’ model were then compared with the expenditure forecast provided by ILPI in its revenue application.

**Figure 3.2: Total Opex (PhP million, real 2008)**



Source: ILPI Application May, 2008

PB Associates’ opex forecasting model forecasts by escalating the base year values of opex in different broad cost categories to reflect forecast changes in key cost drivers. For example the key cost driver for changes in opex for the operation and maintenance of distribution system network assets is the change in the size of the asset base, which is

closely aligned to proposed capex. Similarly the key cost driver for changes in the opex for regulated retail services expenditures is the change in customer numbers<sup>18</sup>.

The opex in the base year is used as the starting point for the extrapolation. However, this base year has first to be tested for cost efficiency and any one-off or non-business-as-usual expenditures in the base year have to be removed prior to modelling, since such expenditures would not be incurred over the forecast period. Furthermore, additional expenditures, or expenditures on new initiatives that are not included in the base year forecast, need to be reviewed and modelled independently. Such expenditures are then added to the base opex derived from PB Associates' model to determine the total forecast annual expenditure.

Hence the overall process we used to assess ILPI's efficient and prudent annual opex forecasts included the following steps:

- Determine the base year opex for each cost category;
- Confirm that the base year opex is efficient;
- Identify opex cost drivers;
- Project the base year opex forward for each year of the forecast period, taking into account projected changes in the cost drivers;
- Compare ILPI's base forecasts with our model forecasts and test for relative efficiency;
- Assess each component of the additional expenditures individually, compare them to ILPI's forecast expenditures and develop recommended allowances; and
- Combine the recommended base opex forecasts and our additional expenditure recommendations to obtain the total recommended annual opex forecast.

These steps are discussed in more detail in the following sections.

### 3.3.1 Determination of Efficient Base Year Opex

In order to assess the efficiency of the base year opex we used the following two approaches.

- We benchmarked the opex against the opex of the other IOUs that are entering PBR at the first or second entry points.
- We reviewed the itemized CY 2007 opex to identify line items that appeared abnormally high or low. Identified line items were reviewed in more detail and adjusted as necessary to ensure that the line item represented an efficient use of funds and was consistent with expected recurring expenditure levels for that line item.

#### 3.3.1.1 Benchmarking

Benchmarking provides an indication of the relative performance of different utilities and is often used internationally for this purpose, not only by regulators but also by utilities

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<sup>18</sup>

In our extrapolation of base year opex we have modified PB Associates' model so that the first forecast year following the base year CY 2007 is RY 2009. This means that there is no duplication of the costs shown in the model and the opex over the three month intervening period (1 January – 31 March 2008) is not shown. We have however adjusted the escalation factors that apply between CY 2007 to RY 2009 to reflect anticipated changes in the cost drivers over this three month period.

themselves. As a performance assessment tool, benchmarking has limitations because each business is different and it is difficult to ensure that these differences are properly accounted for in making performance comparisons. It is also necessary to ensure that the indicators used for benchmarking are measured in a similar way by each utility. However, these measurement issues can be minimized by benchmarking at a high level. For example, for our benchmarking analysis, we have used total opex as a performance indicator because the measure will not be affected by differences between businesses in the allocation of expenditures to different line items.

In spite of these limitations, benchmarking can provide a useful indication of the relative efficiency of different utilities, particularly where a utility performs consistently well or poorly across a range of normalized indicators.

We have considered a range of possible performance indicators and, having regard to the availability of data, we have identified the following normalized indicators as being particularly appropriate for assessing the relative efficiency of the reported opex spend.

- *Ratio of total opex to kWh sold.* Total opex is one of the building blocks of PBR and the normalized indicator is a direct measure of one of the main components of the MAP.
- *Ratio of total opex to the optimized replacement cost (ORC) of the RAB.* This indicator is relevant because the size of the asset base is one of the key drivers of opex and ORC is the best measure of the size of the asset base.
- *Ratio of total number of customers to total employees.* This is a commonly used indicator of staff productivity and is one of the performance indicators used in MERALCO's annual report. Its main limitation is that the ratio may be influenced by the extent to which a utility outsources the construction and maintenance of distribution system assets. We have no information on the total staff numbers of the first entry point utilities but have taken MERALCO's ratio from its 2007 annual report.
- *Ratio of total number of customers to total number of administration employees.* We have used this ratio in order to mitigate problems arising from the use of the total staff indicator. The use of this indicator assumes that only special administrative projects are outsourced. We were unable to measure this ratio for any of the three first entry point utilities.

We also tried to develop a measure of average salary levels to use as a benchmark. However we were unable to develop a measure that seemed sufficiently robust to use as a reliable benchmark, possibly because of differences between the three IOUs in the manner in which staff related costs were identified and allocated to the different line items.

The benchmark data for the second entry point IOUs was taken from their revenue applications or from their asset valuation reports, while data for the first entry point utilities was taken from their final determinations for RY 2008, the first year of their second regulatory period. Hence the performance indicators of the first entry point IOUs can be considered to represent the ERC's view of an efficient level of operation at this time and thus form a reasonable baseline for assessing the relative efficiency of the second entry point IOUs.

In developing measures to use for benchmarking the second entry point IOUs, we made the following adjustments to the RY 2007 total opex reported in their revenue applications.

- We adjusted out the RY 2007 opex related to the operation and maintenance of CLPC's generating station, since neither ILPI nor MECO operate a generation plant.

- We adjusted out the estimated component of total opex related to installation of capital assets. This adjustment was part of the expenditure review for both ILPI and MECO in order to ensure that forecast and historic expenditures were directly comparable and that there was no double counting. In the case of CLPC, a similar adjustment was not necessary for the expenditure review as the cost allocation methodology used for both historic and forecast expenditure streams was similar<sup>19</sup>. However in order to ensure comparability of the CLPC opex with the adjusted opex of the other two second entry point IOUs it is necessary to adjust out CLPC's in-house capex related labor costs. As a first approximation this was assumed to be 50% of the average relative adjustment of ILPI and MECO<sup>20</sup>. This adjustment is only an approximation but we are satisfied that any inaccuracies were not material, in that they have not affected the indicative conclusions made from our benchmarking analysis.
- The value of CLPC's generation plant was not included in the ORC of the CLPC asset base.
- Staff used for the operation of CLPC's generation plant were not included in CLPC's total staff numbers.

The benchmarking data and the normalized benchmarks are shown in Table 3.5.

**Table 3.5: Benchmark Data and Normalized Benchmarks.**

	Second Entry Point (CY 2007)			First Entry Point (RY 2008) <sup>1</sup>		
	CLPC	ILPI	MECO	CEPALCO	DECORP	MERALCO
<b>Data</b>						
Energy Sales (GWh)	117.5	175.7 <sup>2</sup>	238.2	686.3	219.4	26,242.5
Customers	27,966	44,357	58,551	109,672	83,224	4,416,999
ORC (PhP million)	682.06	791.71	918.50	2,966.51	1,347.78	155,257.93
Total Opex (PhP million)	71.91	108.67	57.95			
Adjustment (PhP million)	(2.90)	(6.74)	(5.76)			
Adjusted Opex (PhP million)	69.01	101.93	52.19	217.19	107.08	11,496.72
Total Staff	48	161	69			
Admin Staff	21	71	32			
<b>Normalized Benchmarks</b>						
Adjusted Opex / kWh	0.59	0.58	0.22	0.32	0.49	0.44
Adjusted Opex / ORC	0.10	0.13	0.06	0.07	0.08	0.07
Customers per employee	583	276	849			747
Customers per administration employee	1,332	625	1,830			

Note 1: The second regulatory period for the first entry point IOUs is from 1 July 2007-30 June 2008.

Note 2: Includes customers connected at 69 kV

Table 3.5 indicates that ILPI does not benchmark well against the first entry point utilities in terms of both adjusted opex per kWh and staff numbers. In particular ILPI has a much higher staffing level than either of the other second entry point IOUs. We have seen an old analysis of publicly available National Electrification Authority data (2002) that shows that the customers per employee of electric cooperatives ranged at the time from a high of 468 to a low of 98 with an average of 261. We would expect all IOU's to be at the high

<sup>19</sup> For both historic and forecast expenditure streams, all in-house labor was charged to opex but all contracting costs were capitalized.

<sup>20</sup> The adjustment was limited to 50% as CLPC's outsourced labor costs are already capitalized.

end of this range given the acknowledged inefficiency of many electric cooperatives, whereas ILPI benchmarks only marginally better than average. We think its high staff numbers are the likely reason for its relatively poor performance across all benchmark indicators.

### **3.3.1.2 Review of Opex Line Items**

As noted above, PB Associates' opex model is based on the assumption of business as usual in forecasting future opex and changes in future expenditure patterns need to be modelled independently. In addition any one-off or non-business-as-usual expenditures as well as expenditures that are considered inefficient, that are included in the base year costs, need to be identified and backed out of the base year costs prior to modelling. Hence ILPI was requested to provide information with regards to any known changes in future expenditure patterns or any one off expenditures included in the base year costs which did not represent business as usual expenditures.

#### *Distribution System Operations - Information Technology*

The historic and future expenditure for distribution system operations related information technology fluctuates with the purchase of software packages. More specifically, expenditure for this line item in the RY 2007 base year seems to be high due to the acquisition of a SynerGEE Reliability and Protection module, as noted in submissions made by ILPI after the clarificatory meeting. For this reason we used the average expenditure over CY 2004-07, as the base year expenditure. The magnitude of this downward adjustment is PhP 0.17 million.

#### *Distribution Systems Operations – Miscellaneous Expenditure*

The miscellaneous expenditure line item in the distribution system operations category is higher in the base year than any historic (CY 2004-07) or forecasted (RY 2009-13) year. For this reason we used the average expenditure over CY 2004-07, as the base year expenditure. The magnitude of this downward adjustment to the base year is PhP 0.58 million.

#### *Administrative and General Expenditures – Information Technology*

In ILPI's additional information submission, details were provided that identified the acquisition of Windows Server Operating System and an SQL Server License, at a cost of PhP 0.55 million. This was a one-off cost found only in the base year of the information technology line item in the administrative and general expenditures category. For this reason we used the average expenditure over CY 2004-07, as the base year expenditure. The magnitude of this downward adjustment to the base year is PhP 0.45 million.

The impact of the aforementioned adjustments on the base year opex used in our model is shown in Table 3.6.

**Table 3.6: 2007 Opex Adjustments (PhP million, real 2008)**

	<b>CY 2007</b>
<b>Adjusted RY 2007 opex (Table 3.3)</b>	<b>101.93</b>
Adjustments	
Distribution System Operations - Information Technology	(0.17)
Distribution System Operations – Miscellaneous Expenditure	(0.58)
Administrative and General – Information Technology	(0.45)
<b>Revised RY 2007 base opex</b>	<b>100.73</b>

The 2007 base year opex, incorporating our recommended adjustments, used for modelling future expenditures are as shown in Table 3.7:

**Table 3.7: Base 2007 Opex (PhP million, real 2008)**

<b>Operational Expenditure Category</b>	<b>CY 2007</b>
Operation	17.44
Maintenance	14.83
Administration and General	47.84
Regulated Retail Services	20.62
<b>Total Operational &amp; Maintenance Expenditure</b>	<b>100.73</b>

Source: PB Associates based on ILPI data, also includes adjustments for the exclusion of capex installation related costs

### 3.3.2 Identification of Cost Drivers and Impact of Efficiency Initiatives

We have used the following cost drivers in our opex model:

- *Size of the Asset Base*

We have used the undepreciated ORC value of the RAB as a surrogate for asset size, but have modified the RAB going forward to compensate for the impact of refurbishment and renewal capex on future opex. We consider that renewal and refurbishment capex replaces existing assets at or near the end of their service lives and therefore reduces the opex required to maintain these assets.

We also believe that the commissioning of new assets results in lower forecast opex as these new assets generally require minimal condition based maintenance during the regulatory period in which they are commissioned. Our experience is that the savings in forecast opex resulting from the commissioning of new assets or the replacement of aged assets averages 20% and this efficiency factor has been incorporated into PB Associates' opex forecasting model.

In addition numerous studies carried out by PB Associates, including in the Philippines, indicate that on average the variable component of the administrative & general expenditure is 10%. Only this variable component of administrative and general has been escalated in PB Associates' opex model.

In determining the RAB for each year of the forecast period we took into account the recommended reductions in capex identified in Section 2.7.

o *Customer Numbers*

We have modelled the impact of increasing customer numbers on the regulated retail services opex as there is a well accepted correlation between regulated retail service expenditures and customer numbers.

In our model we made no changes to the customer numbers forecast by ILPI.

o *Material Prices*

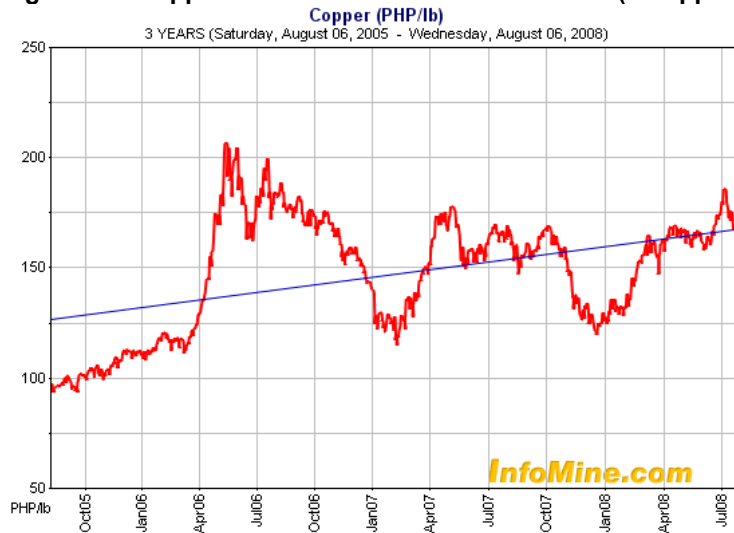
PB Associates' opex model allows real growth inflators to be input for both material and labor costs.

By looking at Figure 3.3 and 3.4, it is clear that copper and aluminium prices have not changed significantly over the past three years. Other major cost drivers that may influence material cost include exchange rates as well as the market conditions for electrical equipment. It is difficult to predict how the exchange rate changes and market conditions for electrical equipment will influence material costs and therefore we assumed that these factors will remain relatively constant over the regulatory period. Hence we have assumed that equipment costs will remain constant in real terms. This means that nominal material costs will increase over the forecast period in line with forecast CPI.

**Figure 3.3: Aluminium Prices over a Three-Year Period (Philippine Peso/Pound)**



Source: [www.infomine.com](http://www.infomine.com)

**Figure 3.4: Copper Prices over a Three-Year Period (Philippine Peso/Pound)**

Source: [www.infomine.com](http://www.infomine.com)

The model further assumes that material costs comprise 25% of total costs for office based functions such as administrative and general, 20% for operations and 30% for maintenance.

o *Labor Costs*

Labor costs form a significant proportion of operating and maintenance costs and hence our model allows this variable to be altered to reflect any expected real change in labor costs. It is recognised that it is always difficult to select an appropriate real escalator for future labour rates and our modelling was carried out with the real labor escalator set to -1%. This allows labor costs to increase at 1% less than the rate of inflation.

We believe that a reasonable base assumption is that unit labor costs or wage rates will remain constant in real terms. Labor costs are a very significant driver of inflation and economic theory indicates that increases above the rate of inflation cannot be sustained over time unless there are real increases in productivity throughout the economy. No evidence has been provided that labor costs for electricity distribution workers will, on average, escalate at a rate that is materially different from labor costs in other sectors of the economy.

We note also that labor costs form a significant component of the distribution wheeling rate and all utilities must carefully manage their labor costs if electricity prices are to be contained. Utilities have more control over the cost of labor than over the cost of materials and for this reason regulators are very reluctant to allow prices that reflect real increases in labor costs, unless there is a compelling reason to do so. We would point out that controlling labor costs is not simply a matter of limiting wage rates. Other tools that are potentially available include reducing staff numbers, increasing the level of outsourcing and multi-tasking.

We have adopted this base assumption for all three second entry point IOUs. However the benchmarking analysis described in Section 3.3.2.1 found that ILPI did not benchmark well for labor utilization when compared to the other two second entry point IOUs or, more generally, to the labor utilization of electric cooperatives. This indicates that there is a potential for ILPI to reduce its labor costs by reviewing the way it utilizes its workforce with a view to using it more efficiently. We have therefore modelled ILPI's opex requirements using a relatively modest negative labor escalator and believe that the efficiency gains indicated by the use of this escalator should be readily achievable. We are not

suggesting, however, that these efficiency gains should or could be achieved by driving down real wage rates.

### 3.3.3 Additional Opex

Additional opex is expenditure above and beyond expenses incurred in a business-as-usual environment or expenditure on new initiatives where costs were not incurred in the base year and hence have not been allowed for in our modelling.

One such additional expenditure identified in the ILPI application is the establishment of a call center with four new staff members functioning on a one-person-per-shift basis. In our modelling we have considered this additional staff cost as well as the acquisition of software for the call center as additional expenditure because the call center is a new initiative that was not included in the base year cost of our model. The cost for the proposed additional staff was added to the model for each regulatory year and amounts to PhP 1.14 million per year. The call centre software will be acquired in RY 2009 at a cost of PhP 0.19 million.

In assessing the forecast administrative and general expenditures, we noted that the forecast property insurance line item increased substantially relative to the historic levels. In ILPI's additional submission, some detail was provided regarding this substantial increase including supporting documentation from an insurance broker<sup>21</sup> to support expenses forecasted for insuring machinery breakdowns at different substations. Based on this supporting information, we have considered this cost to be an additional expenditure over the regulatory period. This amounts to an increase of PhP 0.79 million per year.

### 3.3.4 Implementation of DSOAR

Prior to the implementation of DSOAR, ILPI was unable to charge customers directly for work, such as connections and disconnections, which is undertaken at the request of, or for the benefit of, individual customers. Once DSOAR is implemented, such work will be considered potentially contestable and ILPI will be able to apply to ERC for approval to charge customers directly for these services. We acknowledge that this process is time consuming and that the outcomes at this stage are uncertain. Nevertheless it seems reasonable to assume that income resulting from the implementation of DSOAR has the potential to increase progressively over the second regulatory period and that some provision should be made for this in the opex forecast<sup>22</sup>. If no provision is made there will be a double recovery of costs for any services provided under DSOAR, through the distribution wheeling rate and also through the charges made directly to customers. Inclusion of a DSOAR provision will provide ILPI with an incentive to take the necessary action to recover revenue directly from customers where appropriate and not to continue to rely on cost reimbursement through the regulated distribution wheeling rate.

We therefore propose to reduce our recommended total distribution system operation and maintenance expenditure on a sliding scale commencing at 1% in RY 2010 through to 4% in 2013 to avoid the potential double recovery of costs that can be recovered directly from customers under the DSOAR provisions. No adjustment is recommended for RY 2009.

This adjustment is shown in Table 3.8 below.

<sup>21</sup>

PNB General Insurers Co Inc.

<sup>22</sup>

It is noted that ILPI is able to deduct any costs associated with providing related business revenue from the net income derived before declaring the net profit from these services to the ERC. In terms of clause 4.3 of the RDWR, 50% of the net profit will be taken into account in the annual resets of the maximum average price cap. It is therefore also in ILPI's own interest to recover these costs directly from customers.

**Table 3.8: Recommended Adjustment for DSOAR Recoveries (PhP million, real 2008)**

	RY 2010	RY 2011	RY 2012	RY 2013
<b>Recommended Distribution System Operation and Maintenance</b>	36.01	37.35	37.34	37.56
<b>Recommended Adjustment</b>	(0.36)	(0.75)	(1.12)	(1.50)

### 3.4 RECOMMENDED OPERATIONAL EXPENDITURES

As discussed in Section 3.3.2 above, we have used PB Associates' opex model to forecast future base opex with the real labor inflator set at -1% and the real material inflator set at 0%. With these inputs the model produced the forecast base opex shown in Table 3.9 after the addition of the additional expenditures discussed in Section 3.3. We have shown the DSOAR adjustment in Section 3.3.4 separately.

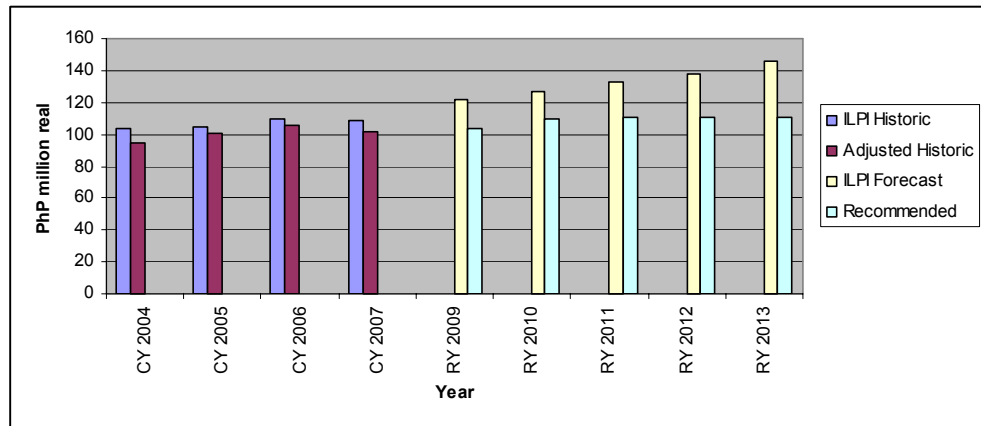
Table 3.9 also compares, for each major opex category, our annual forecast opex with the forecast opex ILPI included in its revenue application.

**Table 3.9: Comparison of ILPI and Recommended Forecast Opex (PhP million, real 2008)**

	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
<b>Distribution System Operations</b>					
Revenue Application Forecast	19.10	20.23	20.17	20.89	21.74
Model	18.18	19.45	20.17	20.15	20.26
DSOAR Adjustment		-0.19	-0.40	-0.60	-0.81
<b>Recommended Opex</b>	<b>18.18</b>	<b>19.26</b>	<b>19.76</b>	<b>19.55</b>	<b>19.45</b>
<b>Distribution System Maintenance</b>					
Revenue Application Forecast	15.99	17.50	19.44	20.11	20.90
Model	15.46	16.56	17.18	17.19	17.30
DSOAR Adjustment		-0.17	-0.34	-0.52	-0.69
<b>Recommended Opex</b>	<b>15.46</b>	<b>16.39</b>	<b>16.84</b>	<b>16.67</b>	<b>16.61</b>
<b>Regulated Retail Services</b>					
Revenue Application Forecast	26.76	24.81	25.01	25.67	26.40
Recommended Opex	21.90	23.72	24.05	24.59	25.15
<b>Administrative &amp; General Expenditure</b>					
Revenue Application Forecast	60.18	64.02	68.18	71.34	76.55
Recommended Opex	47.96	50.11	49.80	49.48	49.20
<b>Totals</b>					
Revenue Application Forecast	122.04	126.56	132.81	138.01	145.58
Recommended Opex	103.51	109.48	110.45	110.29	110.41
<b>Recommended Adjustment</b>	<b>-18.53</b>	<b>-17.08</b>	<b>-22.36</b>	<b>-27.72</b>	<b>-35.17</b>
Percentage Adjustment	-15.2%	-13.5%	-16.8%	-20.1%	-24.2%

Source: PB Associates

A graphical comparison between ILPI's forecasts and our forecast opex is shown in Figure 3.5. In comparing the forecast opex with historic trends it should be remembered that the adjusted historic opex is the more valid comparison because it does not include any capex related expenditure.

**Figure 3.5: Comparison between ILPI and Recommended Opex Forecast (PhP million, real 2008)**

ILPI's opex modelling shows regulated retail services expenditures increasing 6.4% over the second regulatory period and administration & general expenditures increasing 19.6% over the same period. However our modelling indicates a lower percentage increase of 6% for regulated retail services and -1.8% for administration & general expenditure. ILPI's modelling forecasts distribution and connection services opex to increase by 13.0% over the regulatory period whereas our modelling indicates a lower percentage increase of 1.1% over the same period.

With regard to regulated retail services, there is a relationship between the number of customers connected to the ILPI network and the annual consumer accounts opex and we have assumed that expenditure in this category will increase in real terms at the same rate as growth in customer numbers. This operational area is one where it is relatively easy for a large utility to achieve efficiencies of scale with the use of computerisation and business process redesign. However it is more difficult for a small utility like ILPI to achieve similar cost efficiencies and our modelling reflects this. It is likely that the difference between ILPI's forecast and our modelling is primarily due to our assumption that labor costs will reduce over the forecast period.

ILPI forecasts administrative and general expenditures to increase 19.6% in real terms over the regulatory period. We believe an increase of this magnitude is also difficult to justify as there are many opportunities to achieve scale and scope efficiencies in these business functions, even for a small utility. It is likely that the differences between ILPI's forecast opex and the opex shown by our model are due primarily to:

- Our exclusion of administrative and general expenditures related to the acquisition of TransCo's subtransmission assets. These expenditures totalled PhP 23.69 million over the forecast period and their exclusion is consistent with our recommendation not to include costs associated with the purchase of TransCo assets in the PBR revenue requirement. We acknowledge that there will be costs associated with the operation of these assets and these costs should be included in the analysis of the impact of the purchase on customer rates, which we anticipate that the ERC will require ILPI to provide with its application to approve any purchase contract.
- our assumption that 90% of administrative and general expenses are fixed and that the cost of this component will not change in real terms over the forecast period; and
- our assumption that total labor costs will reduce in real terms over the forecast period.

We are less clear on the basis on which ILPI is likely to have forecast its opex for the operations and maintenance of distribution network assets. However, factors driving the forecast opex reductions indicated by our modelling are likely to include:

- the impact of reductions in forecast capex and in particular the removal of the capex provision for the purchase of the TransCo line and other follow-on projects; and
- our assumption that total labor costs will reduce in real terms over the forecast period.

## 4. TAXES LEVIES AND DUTIES

### 4.1 HISTORICAL AND FORECAST TAXES, LEVIES AND DUTIES

#### 4.1.1 Historical Taxes, Levies and Duties Expenditure

ILPI's historical expenditure on taxes levies and duties over the period CY 2004-07 is shown in Table 4.1. The average annual expenditure over this period was approximately PhP 0.09 million.

**Table 4.1: Historical Taxes, Levies and Duties (PhP million, nominal)**

Year	CY 2004	CY 2005	CY 2006	CY 2007
<b>Taxes, Levies and Duties</b>	0.09	0.09	0.09	0.09

Source: PB Associates based on ILPI Application, May 2008

In order to have a better assessment of the relative expenditure, the actual historic expenditures were inflated to real 2008 PhP using actual historic inflation indicators. The table below shows the actual historic taxes, levies and duties expenditure in real 2008 PhP.

**Table 4.2: Historical Taxes, Levies and Duties (PhP million, real 2008)**

Year	CY 2004	CY 2005	CY 2006	CY 2007
<b>Taxes, Levies and Duties</b>	0.11	0.10	0.10	0.09

Source: PB Associates based on ILPI Application, May 2008

The average annual expenditure over this period in real terms was approximately PhP 0.10 million.

#### 4.1.2 Forecast Taxes, Levies and Duties Expenditure

ILPI's forecast taxes, levies and duties are shown in Table 4.3.

**Table 4.3: Forecast Taxes, Levies and Duties (PhP million, real 2008)**

Year	CY 2008	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
<b>Taxes, Levies and Duties</b>	0.21	1.07	2.54	1.61	1.24	1.07

Source: PB Associates based on ILPI Application, May 2008

The average annual taxes, levies and duties expenditure forecast for the second regulatory period, which excludes CY 2008 and RY 2009 is approximately PhP 1.62 million. The main components contributing to the significant increase in taxes, levies and duties for the second regulatory period when compared to the CY 2008 budget and the RY 2009 forecast are the regulatory reset expert fees and the real property taxes. These costs are discussed in Section 4.3 below.

### 4.2 TAXES, LEVIES AND DUTIES BREAKDOWN

#### 4.2.1 Historic Taxes, Levies and Duties Expenditure Breakdown

ILPI's taxes, levies and duties over the CY 2004-07 period are presented in Table 4.4 below. Real property tax, on average, comprises 78% of the total annual taxes, levies and duties expenditure over that time.

**Table 4.4: Disaggregated Historic Taxes, Levies and Duties (PhP million, real 2008)**

Year	CY 2004	CY 2005	CY 2006	CY 2007
<b>Taxes</b>				
Real Property Tax - Land and Buildings	0.085	0.079	0.074	0.072
Real Property Tax - Machineries	-	-	-	-
Real Property Tax - Proposed Building	-	-	-	-
Business Operation Permits	0.011	0.010	0.010	0.010
Community Tax	0.013	0.012	0.011	0.011
<b>Levies</b>				
Regulatory Reset Expert Fees	-	-	-	-
<b>Duties</b>				
<b>Taxes, Levies and Duties</b>	<b>0.11</b>	<b>0.10</b>	<b>0.10</b>	<b>0.09</b>

Source: PB Associates based on ILPI Additional Information Submission, July 2008

**4.2.2 Forecast Taxes, Levies and Duties Expenditure Breakdown**

ILPI's forecast expenditure on taxes, levies and duties can be disaggregated into the components shown in Table 4.5 below. It can be seen that the two components of regulatory reset expert fees and real property tax, on average, comprise 99% of the total annual taxes, levies and duties expenditure across the second regulatory period.

**Table 4.5: Disaggregated Forecast Taxes, Levies and Duties (PhP million, real 2008)**

Year	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
<b>Taxes</b>					
Real Property Tax - Land and Buildings	0.069	0.069	0.069	0.069	0.069
Real Property Tax - Machineries	0.978	0.978	0.978	0.978	0.978
Real Property Tax - Proposed Building	0.006	0.006	0.006	0.006	0.006
Business Operation Permits	0.009	0.009	0.009	0.009	0.009
Community Tax	0.011	0.011	0.011	0.011	0.011
<b>Levies</b>					
Regulatory Reset Expert Fees	-	1.469	0.540	0.172	-
<b>Taxes, Levies and Duties</b>	<b>1.07</b>	<b>2.54</b>	<b>1.61</b>	<b>1.24</b>	<b>1.07</b>

Source: PB Associates based on ILPI Additional Information Submission, July 2008

**4.3 COMMENTARY**

The taxes, levies and duties expenditures in ILPI's revenue application relate only to the distribution business and not to any non-distribution related businesses. The main increases arise from expenditures for regulatory reset expert fees and real property taxes. These are discussed further in the sections below.

**4.3.1 Regulatory Reset Expert Fees**

As stated in Section 2.3.3 of the Position Paper, the costs for the Regulatory Reset Experts during the Second Regulatory Period are considered to be a levy and are recoverable under the "levies, duties or taxes other than corporate income tax" building block. Furthermore, the Position Paper states that ERC will provide IOUs with the forecast costs to be included in their Revenue Applications.

As part of its application, ILPI has included the following amounts which consist of the costs for the engagement of experts to undertake the asset valuation; review the expenditure forecasts; prepare the Issues Paper and Position Paper; and to assist the ERC with financial modelling and project management:

**Table 4.6: Forecast Regulatory Reset Expert Fees (PhP million, real 2008)**

Year	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Regulatory Reset Expert Fees	-	1.47	0.54	0.17	-

Source: PB Associates based on ILPI Application, May 2008

#### 4.3.2 Real Property Taxes

Table 4.7 below provides the real property taxes that ILPI has included in its application:

**Table 4.7: Forecast Real Property Taxes (PhP million, real 2008)**

Year	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
Real Property Taxes	1.05	1.05	1.05	1.05	1.05

Source: PB Associates based on ILPI Application, May 2008

This component pertains to real property taxes for land and buildings as well as the provision for real property taxes on machineries and the proposed Luinab building. It should be noted however that ILPI did not provide sufficient information to clearly explain its liability for the payment of real property taxes on machineries nor how the provision for real property tax on the proposed new Luinab building was determined.

#### 4.3.3 Permit Fees

We note that ILPI has made no provision for Permit Fees payable to ERC in respect of opex and assume that these fees have been included in the opex forecast. This treatment is appropriate.

#### 4.4 RECOMMENDATIONS

Upon the detailed review of each line item of the taxes, levies and duties expenditure application of ILPI we have arrived at the following recommendations:

- The component of provision of real property taxes on the machineries as well as the proposed Luinab building should be excluded from the annual revenue requirement because insufficient information has been provided to satisfy us of ILPI's liability for these payments. Only taxes for which ILPI's liability has been legally established and confirmed at the time of this expenditure review should be included in the revenue requirement. Taxes for which ILPI's liability has not been confirmed or is in dispute before the courts should not be included. In the event that ILPI's liability for these taxes is legally confirmed or that ILPI becomes liable for new taxes that are not included in the annual revenue requirement, Article XI of the RDWR allows for unexpected tax liabilities imposed during the Second Regulatory Period by means of a "Tax Event Pass Through".
- The component of regulatory reset expert fees for calendar year 2008 should be excluded given that the costs provided by ERC for the regulatory reset expert fees from regulatory years 2010 to 2012 already includes all costs incurred and will be incurred until the end of the Second Regulatory Period.

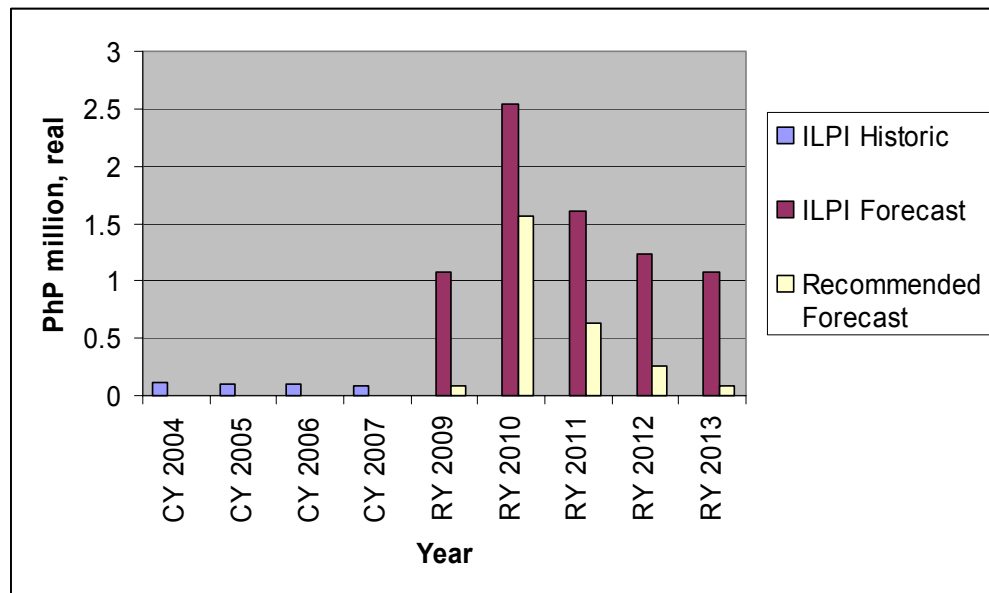
Consequently, our recommended provision for taxes, levies and duties is provided in the table below:

**Table 4.8: Recommended Provision for Taxes, Levies and Duties (PhP million, real 2008)**

Year	RY 2009	RY 2010	RY 2011	RY 2012	RY 2013
<b>Proposed in ILPI's Revenue Application</b>					
Taxes, Levies and Duties	1.07	2.54	1.61	1.24	1.07
<b>Less Adjustments</b>					
Real Property Tax - Machineries	(0.978)	(0.978)	(0.978)	(0.978)	(0.978)
Real Property Tax - Proposed Building	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)
Regulatory Reset Expert Fees	-	-	-	-	-
<b>Recommended Provision for Taxes, Levies and Duties</b>	<b>0.09</b>	<b>1.56</b>	<b>0.63</b>	<b>0.26</b>	<b>0.09</b>

A graphical comparison between ILPI's forecasts and our forecast for taxes, levies and duties is shown in Figure 4.1.

**Figure 4.1: Comparison between Historic and Forecast Taxes, Levies and Duties (PhP million, real 2008)**



The graph shows an average difference between ILPI's forecast and our recommended forecast of 65% over the forecast period.