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Electrical Load Aggregation Assessment of Central Mindanao University Campus, Philippines

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Abstract

The study focuses on evaluating the technical and economic impacts of aggregating the electrical loads that are paid by Central Mindanao University (CMU). Planning was done, by modeling an aggregated electrical distribution system of the university on Powerworld Simulator. Then financial cost comparison on power bills between the existing scenario and proposed electrical load aggregated system was calculated. Savings on load aggregated system was computed. Subsequently economic assessment was executed. In the yardsticks of economic merits, the proposed load aggregated electrical distribution system of CMU will help increase the university's savings on electricity bill.

Keywords: electrical distribution system, load aggregation

1. Introduction

In the recent years, actual power bill of the CMU is 10% higher than its allocated budget (Vagutchay, 2011) and is expected to rise even further with the growing population and continuous development projects that include constructions of infrastructures. With the inevitable rise of power bills, it is about time to develop possible alternatives such as aggregating the electric loads to have better rates option so the university could reduce electricity bills and increase savings.

All buildings/units in CMU are individually metered at the secondary side and supplied with electricity by the First Bukidnon Electric Cooperative

(FIBECO). Each building is billed according to classification of consumers, 76% of electrical consumers that is paid by the CMU are classified as public buildings, 17% are industrial, 6% streetlights and 1% commercial (Nermal, 2013).

Figures 1 demonstrates the existing distribution system, FIBECO serves CMU on three-phase, shown on red lines and single-phase primary lines, shown on yellow-orange lines at 13.8 kV, near the main gate and the University Market, respectively. The distribution system of CMU has a total of 42 transformers, 11 of which are common or owned by FIBECO on blue triangles and 31 are personal or owned by CMU on green triangles. (Jabla, 2011), and Table 1 shows the rate schedule for December 2011 (Nermal, 2013).

Figure 1. Existing distribution lines on campus map

Table 1. FIBECO's revised rate schedule for December 2011

Revised Rate Schedule for December 2011	Low voltage				High voltage
	C	I	P	S	I
Total basic charges (Php/kWhr)	5.9159	5.8449	5.881	6.6296	5.1175
Other fixed charges (Php/consumer)	78.86	78.86	78.86	78.86	78.86
Demand charge (Php/kW)		-5.2281			214.4519

Source: Yap, 2012

Figure 2 indicates that the demand in February 2011 is the highest from 2005-2012 at 154,216.80 kWhr. Figure 3 shows the energy consumption per building in the month of November 2012 (Nermal, 2013).

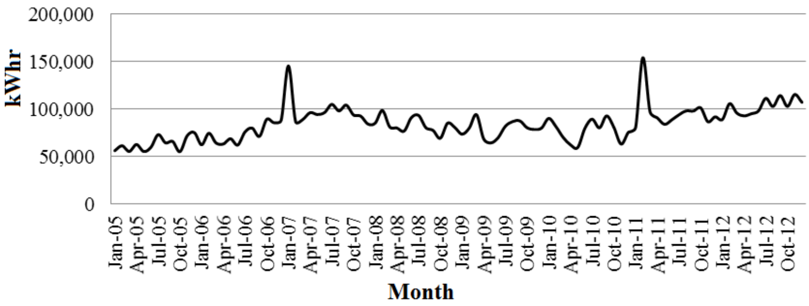

Figure 2. Monthly energy consumption from 2005-2012

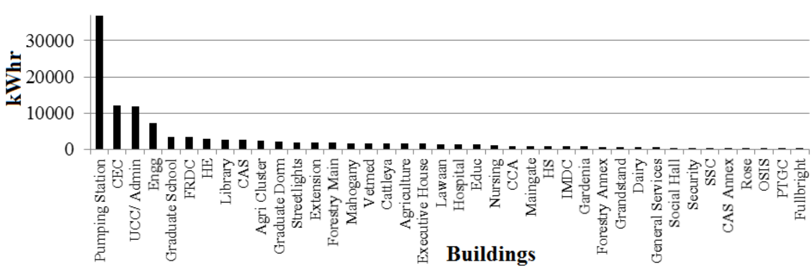

Figure 3. Energy consumption per building/unit for November 2012

In November 2012, CMU paid PhP 753,257.40 for electric bills, and PhP 242,806.20 was accounted for the Pumping Station (Nermal, 2013). The calculated demand is shown in Figure 4, the maximum demand occurred in September 2012 at 331.66 kW. Figure 5 shows the demand per building/unit as of November 2012, indicating that the pumping station has the largest demand.

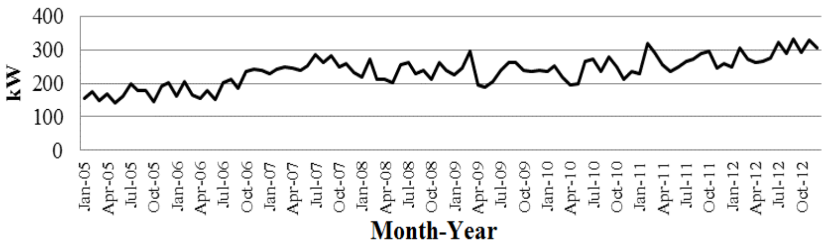

Figure 4. Monthly peak demand from 2005-2012

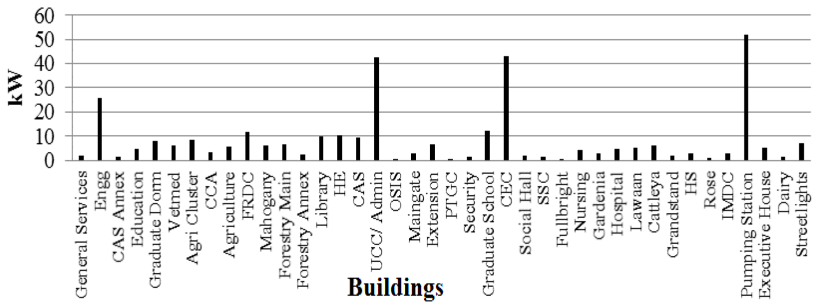

Figure 5. Peak demand per building for November 2012

2. Methodology

The existing system's energy demand and bills were assessed. Then long range demand forecasting (25 years) was projected using Holt-Winter's additive seasonal forecasting method. Having identified the growth areas, the projected load growths, as well as the future additional infrastructure were imposed on the aggregated system modeled on Powerworld Simulator. After that, the base-case scenario was financially compared to the proposed load aggregated system by computing the savings on bills. Then economic cost analysis was done, as PBP, NPV and BCR were considered in choosing the best option.

3. Results and Discussion

3.1. Forecast

The historical energy consumption per month over the past eight years from the electric bills was used in obtaining the energy consumption for the next 25 years. The additional infrastructure was based on historical developments wherein only one building is constructed every five years (Mabelin, 2011), on January 2015, it was assumed to have additional of 1,347 kWhr after the completion of the CAS Annex Extension. Assuming the College of Commerce and Accountancy Building will be finished on January 2020, it will add 2,675 kWhr demand, after five years on January 2025, 1,284 kWhr is added after the completion of the two-storey extension of the hospital. By 2030, additional demand of 1,228 kWhr will be incurred by the New Agri Building. And by year 2035, 3,110 kWhr by the CAS Lab Annex is further added to the forecasted load. Figure 6 shows the historical energy and forecast and Figure 7 the historical demand and forecast.

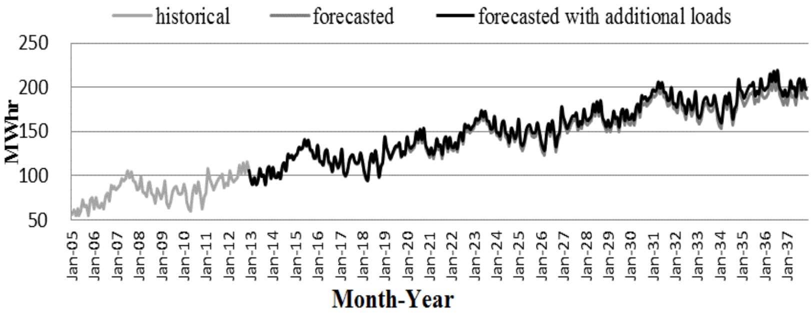

Figure 6. An 8-year historical and 25-year energy forecast with additional loads

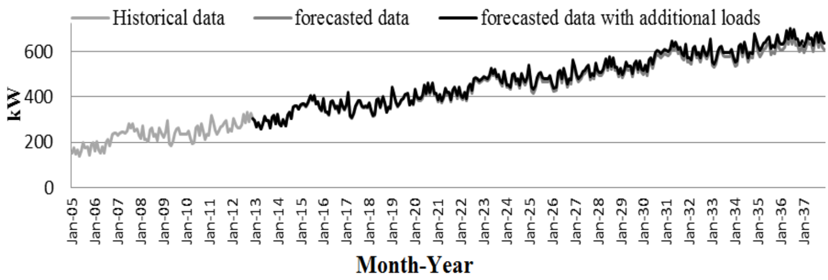

Figure 7. An 8-year historical and 25-year peak demand forecast with additional loads

3.2. Proposed Single Metering Point at the Primary Side, 3-phase 13.8kV (Option 1)

Figure 8 shows the proposed load aggregated system for option 1. The metering point at the primary side, 13.8kV is near the highway, 100 meters south of the maingate and 87 meters east of IMDC. 3-phase primary distribution lines of 2/0 ACSR conductors will distribute electric power to each building.

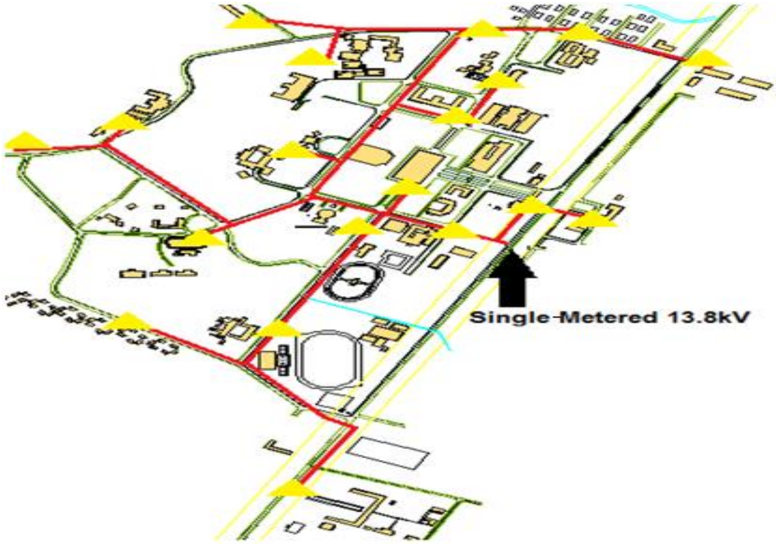

Figure 8. Option 1 distribution map

Figure 9 shows the result of the simulation for actual data of December 2012. All transformers are in normal capacity and all current carrying conductors in the system, are in normal operating conditions. While Figure 10 illustrates the result of the simulation for maximum loading in the next 25 years. Transformers in light orange imply that the transformers nearly exceed its limit; given that transformers once exposed to its limit, at a maximum tolerable time might be damaging. But since it is already at the maximum loading then it is tolerable. At the same time, all other transformers are in normal capacity and all other elements in the system are in normal operating conditions.

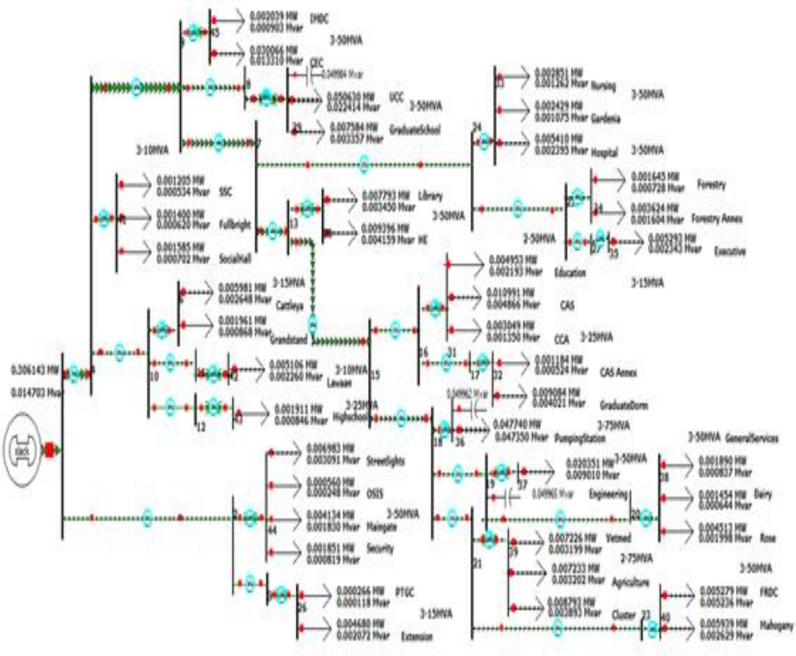

Figure 9. Option 1 as simulated on Powerworld Simulator for December 2012

3.3 Proposed Single Metering Point at the Primary, Side 3-phase 69kV (Option 2)

This option is directly connect to NGCP 69kV line passing through CMU rice fields, a 1 MVA substation 69kV/13.8kV installed at the load center in

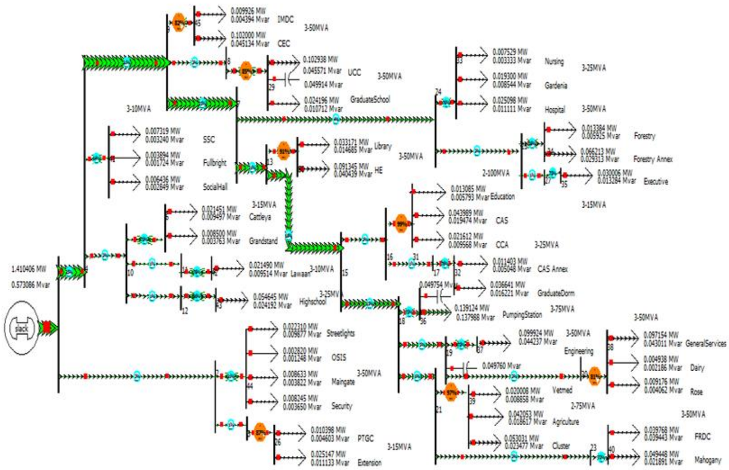

Figure 10. Option 1 on Powerworld Simulator, at max demand in the next 25 years

between the library and the forestry. All current carrying conductors in primary lines are ACSR conductor type sized 2/0. This system has a total of 55 transformers. Figure 11 below shows the proposed load aggregated system. This option could only be possible upon the implementation of Wholesale Electricity Spot Market (WESM) in Mindanao and only if CMU's demand reaches the minimum requirement of 1MW.

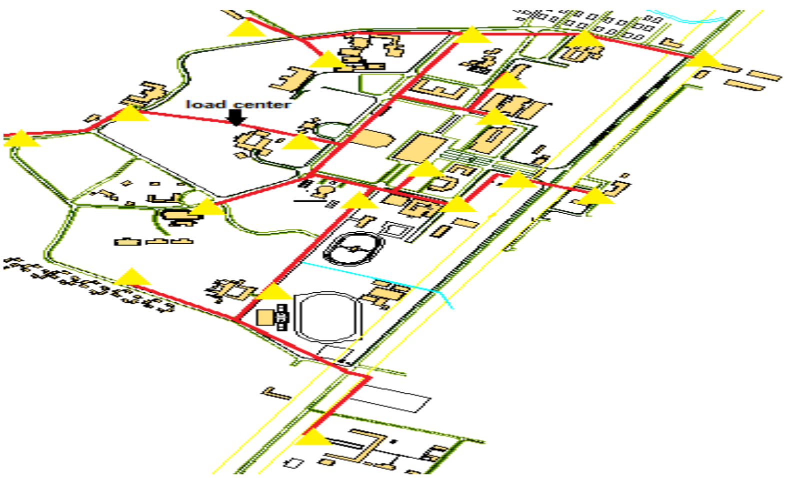

Figure 11. Option 2, Distribution Map

System Model of the actual data of December 2012 was imposed on Powerworld Simulator shown in Figure 12, which indicates that all elements such as transformers and lines in the system are in normal operating conditions. In the same way, Figure 13 illustrates the result of the simulation for maximum loading in the next 25 years. Transformers in light orange indicates a warning that those transformers nearly exceed its limit However, in view of the fact that it is already at the maximum loading then it is still practical, while the rest of the transformers are in normal capacity and all other elements in the system are in normal operating conditions.

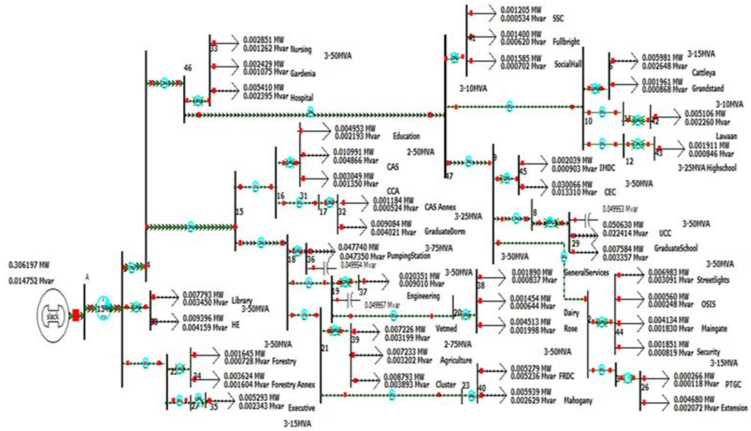

Figure 12. Option 2 as simulated on Powerworld Simulator for December 2012

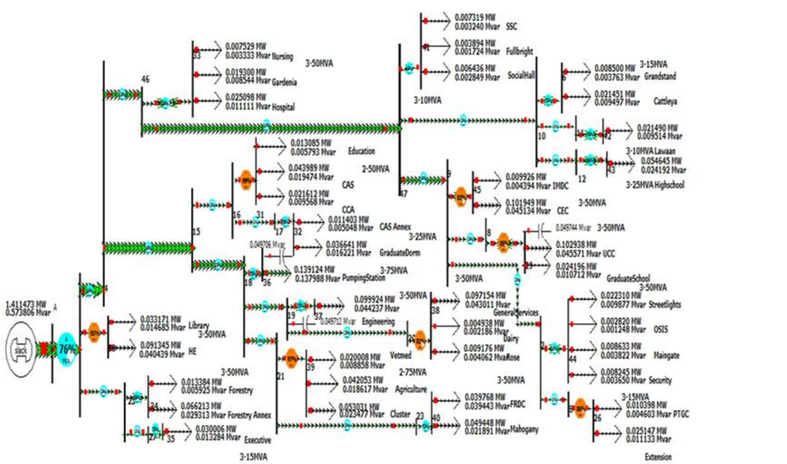

Figure 13. Option 2 on Powerworld Simulator, at max demand in the next 25 years

3.4 Technical Loss Comparison

Figures 14 indicates the technical loss of the proposed options in percentage, comparing it to the entire power of the system for the next 25 years. It implies a minimal loss in contrast to the entire power of the system. Option 1 (black bars) has an average annual loss of 8,078.49 kWhr in the next 25 years while option 2 (white bars) has an average of 12,725.58 kWhr annual loss.

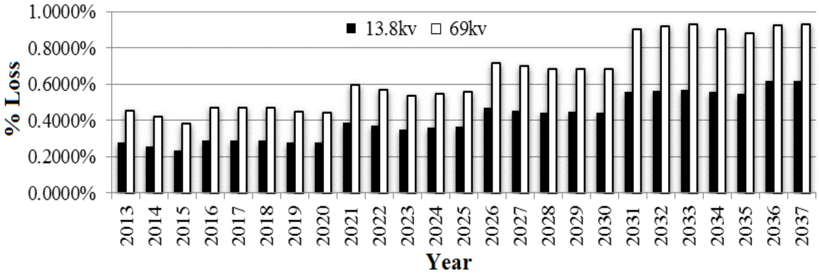

Figure 14. A 25-year comparative graph for % technical loss

3.5 Cost of Load Aggregation

3.5.1 Single Metering at 13.8kV (Option 1)

Data below shows the approximate cost of the materials needed for the load aggregation of this option and the total cost of aggregation, (assuming excess transformer owned by CMU would be sold). Table 2 and 3 show the load aggregation cost of brand new transformers and reconditioned transformers.

Table 2. Load Aggregation cost if brand new transformers are used in Option 1

Total material cost	PhP 5,759,587.03	
Total Labor Cost	PhP 2,015,855.46	
Vat (12%)	PhP 933,053.10	
Contingency (10%)	PhP 870,849.56	
Total cost		PhP 9,579,345.14
less: Transformer, 25 KVA		(PhP30,000.00)
Net cost of Aggregation:		PHP 9,549,345.14

Table 3. Load Aggregation cost if reconditioned transformers are used in Option 1

Total material cost	PhP 4,043,257.03	
Total Labor Cost	PhP 1,415,139.96	
Vat (12%)	PhP 655,007.64	
Contingency (10%)	PhP 611,340.46	
Total cost		PhP 6,724,745.09
less: Transformer, 25 KVA		(PHP 30,000.00)
Net cost of Aggregation:		PHP 6,694,745.09

3.5.2 69KV Primary Metering (Option 2)

Below shows the approximate cost of the materials needed for option 2 and the total cost of aggregation, (assuming excess transformer owned by CMU would be sold), Table 4 and 5 show the cost for brand new transformers reconditioned transformers used for Option 2.

Table 4. Load Aggregation cost if brand new transformers are used in Option 2

Total material cost	PhP 13,712,920.36	
Total Labor Cost	PhP 4,799,522.13	
Vat (12%)	PhP 2,221,493.10	
Contingency (10%)	PhP 2,073,393.56	
Total cost		PHP 22,807,329.14
less: Transformer, 25 KVA		(PHP 30,000.00)
Net cost of Aggregation:		PHP 22,777,329.14

Table 5. Load Aggregation cost if reconditioned transformers are used in Option 2

Total material cost	PhP 11,996,590.36	
Total labor cost	PhP 4,198,806.63	
Vat (12%)	PhP 1,943,447.64	
Contingency (10%)	PhP 1,813,884.46	
Total cost		PhP 19,952,729.09
less: Transformer, 25 KVA		(PHP 30,000.00)
Net cost of Aggregation:		PHP 19,922,729.09

3.6. Cost and Economic Analysis

3.6.1. Cost Comparison

The values of energy and power demand were used to calculate Electricity Bills in pesos, using FIBECO's rates for the existing system and the proposed load aggregation of Option 1. The average annual bill of the existing scenario was found to be PHP 11,977,547.02. For option 1, annual bill was calculated to be PHP 10,780,680.17. For Option 2, assumed rates of NGCP and PSALM were used at 2.8891/kWhr and 401.728/kW (Nermal, Salise and Murillo, 2013) and was computed to be PhP 7,753,249.28 average annual bill, shown in Figure 15.

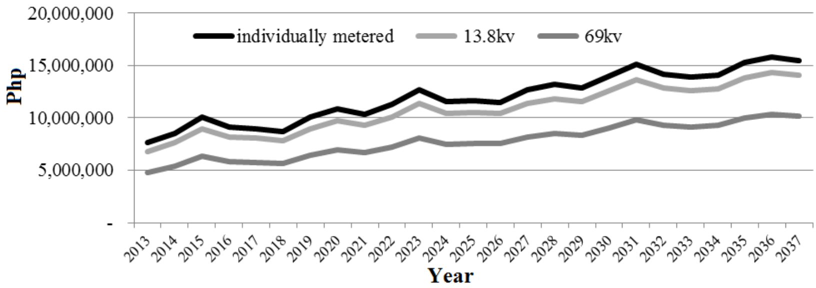

Figure 15. A 25-year comparative graph for annual bills in terms of PhP

Figure 16 compares the annual loss in terms of pesos of both proposed aggregated systems, in view of the fact that the existing scenario has no loss since it is secondary metered, losses are charged to the Distribution Utility in this case FIBECO.

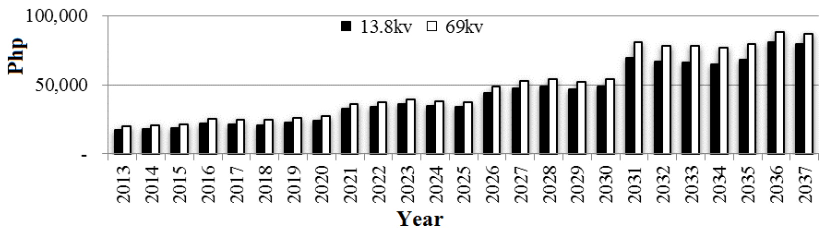

Figure 16. A 25-year comparative graph for annual loss in terms of PhP

3.6.2. Yearly Savings

Table 6 shows the yearly savings on bills against the existing scenario for the next 25 years. For the first option, the average yearly savings on bills is PHP 1,196,866.86 while for option two, PHP 4,224,297.75.

Table 6. Yearly savings on bills

Yearly Savings on Bills		
Year	Option 1	Option2
2013	823,038.83	2,794,490.65
2014	938,689.22	3,162,173.93
2015	1,115,514.80	3,740,935.17
2016	965,067.04	3,314,046.16
2017	926,408.90	3,213,221.15
2018	861,077.89	3,039,209.23
2019	1,062,015.50	3,640,719.67
2020	1,150,758.33	3,943,258.19
2021	1,052,007.33	3,680,890.49
2022	1,164,100.88	4,041,513.96
2023	1,328,656.74	4,580,833.63
2024	1,154,693.20	4,073,433.52
2025	1,146,269.74	4,067,607.81
2026	1,090,684.88	3,946,938.65
2027	1,269,335.87	4,476,596.77
2028	1,317,845.01	4,650,241.86
2029	1,254,785.94	4,475,399.29
2030	1,383,355.07	4,900,113.52
2031	1,510,338.75	5,344,906.03
2032	1,340,564.19	4,866,172.28
2033	1,305,780.29	4,754,483.37
2034	1,298,779.16	4,770,630.28
2035	1,485,953.45	5,327,811.26
2036	1,515,113.79	5,478,628.96
2037	1,460,836.59	5,323,187.80

3.6.3. Benefit - Cost Analysis

Considering the yearly savings in bills, initial investment cost, operation and maintenance expenses and the life cycle cost of transformers used in the proposed load aggregation options, Table 7 indicates the economical advantage of these load aggregation options.

Table 7. Economic analysis

Options	Transformers	NVP	Payback Period	BCR
13.8 kV	brand new	255,954.92	13.03274901	1.022732517
	reconditioned	(1,787,016.47)	15.52520105	0.865661997
69kV	brand new	12,232,135.94	8.889109762	1.438282131
	reconditioned	10,413,869.56	8.988392403	1.350310504

For option 1, the Net Present Value (NPV) is 255,954.92 and a Benefit-Cost Ratio (BCR) of 1.02 justifies the investment and will benefit CMU. Investing in this option will also pay back in 13 years. However, in option 1, if reconditioned transformers are used it will give a negative NPV of (1,787,016.47), and a BCR of 0.87 which means that investing in this option will not give positive contribution to the CMU, although it paybacks in 15.52 years. This is because the life cycle cost of recondition transformer is fairly expensive. While in option 2, NPV is 12,232,135.94 and a BCR of 1.44 which validated the investment and will benefit CMU. Investing in this option will also pay back in 8.88 years. On the other hand, option 2, using reconditioned transformers, will give a NPV of 10,413,869.56, and a BCR of 1.35 which means that investing in this option is also advantageous to the CMU, even if considering the life cycle cost of transformers, since the cost of power substation is far bigger than the cost of the transformers while it paybacks in 8.98 years.

4. Conclusion and Recommendation

The idea of saving money by buying in greater quantities is also the idea in aggregating electric loads to have greater purchasing power than smaller consumers. The goal of this paper is to evaluate the technical and financial impacts of aggregating the electrical loads that are paid by CMU. Data were provided by the CMU and FIBECO. Energy demand in kWhr and power consumption in kW of the University relatively increases over the past years and forecasted by Winter's Method to continually increase in the next 25 years. It was identified that the pumping station has the highest connected load of 36,914.02 kWhr as of November 2012 which is actually 32% of the University's entire energy consumption. Both options of aggregating the electrical loads as proposed on this paper constitute minimal technical loss as to compare it to the total power of the system. For the first option, it gives a maximum percentage loss of 0.6187% and the option 2, has a maximum percentage loss of 0.9310%. Comparing the computed annual bills of the existing scenario and both proposed load aggregation schemes, the aggregation schemes shows a significant savings on power bills, considering the system loss that will be charged on the consumer upon connecting on a primary metering point. This is because the rate for High Voltage Consumers is relatively cheaper than other rates. In the standards of economic analysis, while taking into account the annual savings in bills, initial investment cost, operation and maintenance expenses and the life cycle cost of transformers used in the proposed load aggregation options shows that considering brand new transformer is more economical than using recondition transformers because the life cycle cost of recondition transformers is comparatively more expensive than brand new transformers. Although connecting to the 69kV line of NGCP proves to be the best alternative, the option is still not possible unless CMU will meet the minimum 1 MW requirement of the open access. Until then, connecting to the 13.8 kV of the FIBECO is still the better decision. Based on the results, the proposed load aggregated electrical distribution system will give positive contributions to CMU and help increase savings on power bills.

5. Acknowledgement

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