

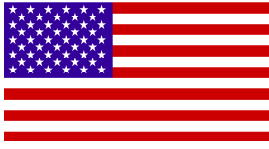
USER'S MANUAL TO THE FULLY ALLOCATED COST OF SERVICE STUDY

FOR
**ISLAMABAD ELECTRIC SUPPLY
COMPANY**

PRODUCED BY:

USAID-POWER DISTRIBUTION PROGRAM

AUGUST 2013



USAID'S POWER DISTRIBUTION PROGRAM

USER'S MANUAL TO THE FULLY ALLOCATED COST OF SERVICE STUDY

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ACRONYMS

1CP	Single Coincident Peak
12CP	Average Monthly Coincident Peak
Amps	Amperes
CDP	Common Delivery Point
CP	Coincident Peak
CWIP	Capital Work in Progress (also, WIP).
DISCO	Government of Pakistan Owned Power Distribution Company
DRA	DISCO Regulatory Account
FAC/FCA	Fuel Adjustment Clause/Fuel Charge Adjustment
FACOS	Fully Allocated Cost of Service Study
FESCO	Faisalabad Electric Supply Company
FPA	Fuel Price Adjustment
GEPCO	Gujranwala Electric Power Company
IESCO	Islamabad Electric Supply Company
KWh	Kilo Watt-hour
KV	Kilo Volt
LESCO	Lahore Electric Supply Company
LF	Load Factor
MDI	Maximum Demand Indicated
MW	Megawatt
MWh	Mega Watt-hour
NARUC	National Association of Regulatory Utility Commissioners
NCP	Non-Coincident Peak
NEPRA	National Electric Power Regulatory Authority
PDP	Power Distribution Program
PKR	Pakistani Rupee
RB	Rate Base
RR	Revenue Requirements
R/C	Revenue to Cost Ratio



T&D Losses	Transmission and Distribution Losses
USAID	United States Agency for International Development
USOA	Uniform System of Accounts
WAPDA	Water and Power Development Authority
WIP	Work in Progress (also CWIP)
WC	Working Capital

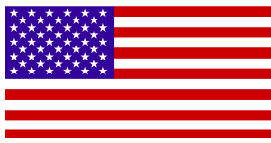
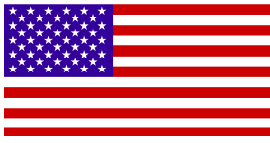


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QUICK STEP GUIDE ON HOW TO USE THE COST OF SERVICE MODEL

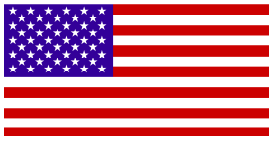
Things to Do:

1. Start with decision worksheets; fill in the eight decision points in the Decision 1 sheet, then review the cells with yellow background in the Decision 2 sheet and adjust as required.
2. Move to the Input Sheets (1-4) and fill these sheets.
 - a. Input 1: Data required to be filled in is shown in red. For convenience, the relevant Islamabad Electric Supply Company (IESCO) Code of Accounts and corresponding National Electric Power Authority (NEPRA) Uniform System of Accounts (USOA) code have also been listed for each data item.
 - b. Input 2: This sheet is to be filled using category-wise customer, sales and revenue data using billing records.
 - c. Input 3: Data inputs needed include the load of each customer category (as well as at each voltage level) coincident with the maximum demand of the year for IESCO and T&D losses at each voltage level i.e. 0.22, 0.4, 11 & 132/66 Kilo Volt (KV). At the moment, this sheet is being filled by data in the Reference Sheets at the end of the model. In the future, it can be filled directly as desired.
 - d. Input 4: The latest tariff schedule determined by NEPRA for IESCO.

Now sit back and relax. The Model will now do its calculations and present the results.

Calculation Sheets:

3. Series of Sheets A, B, C & D are information sheets showing the Model's various stages of implementation.
4. Series A Sheets calculate the billing determinants for two scenarios; Scenario 1 is based on current classification of customer categories while Scenario 2 is based on classification according to the four supply-voltage levels as mentioned above.
5. Series B Sheets show the system classification coefficients, calculation of working capital and calculation of functionally classified rate base.



6. Series C Sheets show the classification and calculation of operating expenses as well as the calculation of total revenue requirements.
7. Series D Sheets show the allocation of costs at various stages for both scenarios, culminating in the allocation of total cost / revenue requirement.

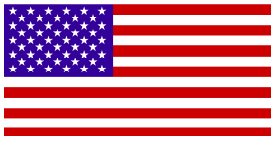
Result Sheets:

8. Series E Sheets show the resultant cost of providing service for each customer category for both these scenarios.
9. Sheet E1.1 calculates the ratio between revenue to be received, based on the latest NEPRA-determined tariffs and the cost to be incurred. This Revenue / Cost Ratio (R/C), if greater than one for any customer category, indicates that this category is cross-subsidizing others while a ratio of less than one indicates that the category is being subsidized.
10. Sheet E1.2 calculates the cost of providing service to each customer category according to the current classification. It must be pointed out that in this sheet, the current tariff structure is rigidly followed with no fixed tariff charged to categories currently exempted from fixed payments based on Maximum Demand Indicated (MDI).
11. It makes more intuitive sense to consider the cost of providing service at each voltage level (as arrived at in Sheet E2.2) as a truer representative of actual cost of service, because the cost should not vary merely due to the occupation of consumer. However, in order to relate to current tariff structure, cost of service in both scenarios has been calculated.

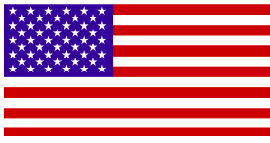
Tariff Design Sheets:

These are three sheets.

- a. The sheet titled “Voltage Differential Tariff” shows tariffs at different voltage levels and for each of current customer categories based on Cost of Service.
- b. The “Existing Tariff Design” sheet takes into account the current level of cross-subsidization and arrives at tariffs for current customer categories while trying to “minimize”, (not eliminate) cross-subsidies.
- c. In the sheet titled “Alternate Design”, an alternative tariff design has been proposed which takes into account the cost of providing electricity at various voltage levels and then classifies customers in a simpler way at each voltage level.



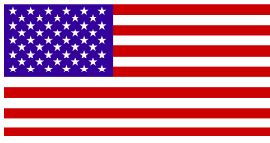
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1. Purpose of the Manual

The purpose of this Manual (the Manual”) is to assist users in using the Fully Allocated Cost of Service Study (FACOS) model for IESCO provided in Microsoft Excel format.

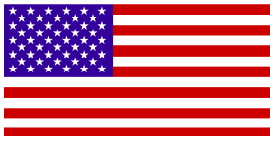
Section 2 of the Manual advises on how to use it. Section 3 provides the scope of the fully allocated cost of service study scenarios and reviews the expected deliverables. Section 4 discusses the methodology and approach followed in this study. Section 5 explains the reasons for two scenarios. Section 6 reviews the structure and standards followed in each scenario. Section 7 is a step-by-step review of the FACOS model with its two scenarios. Finally, Section 8 is a group of technical notes that supports the data compilation to complete the FACOS successfully.



2. How to Use the Manual

The Manual is designed to be read sequentially, one section after the other. Ideally, it should be read twice, once prior to using the excel Model, and then in tandem with the Model on a step-by-step basis. The time estimated for the first read is 160 to 180 minutes, and the second—with the Excel Model open in tandem—close to 120 minutes. The Manual assumes an introductory familiarity with: a) the fundamentals of the electricity sector structure and operations, and b) the embedded Cost of Service Model and principals particularly with its four basic steps of accounts identification, functionalization, classification and allocation of the costs to the different customer classes. Most of the principles related to the cost of service are contained in several sources of which the most important is a manual produced by the National Association of Regulatory Utility Commissioners (NARUC).¹ A bibliography is attached at the end of the Manual for the reader's further use.

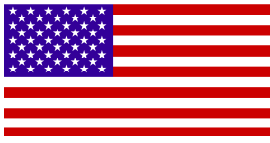
¹ [Electric Utility Cost Allocation Manual](#), NARUC, January 1992.



3. Scope of the Fully Allocated Cost of Service Study Scenarios

The successful population of the two scenarios with the relevant data for the chosen fiscal year should provide the user with the following:

- a. The cost of serving all standard customer classes currently served by IESCO (Scenario 1).
- b. The cost of serving customers at different voltage levels currently served by IESCO (Scenario 2).
- c. The revenue-to-cost ratios for all customer classes currently served by IESCO (Scenario 1).
- d. The revenue-to-cost ratios for customer classes classified by voltage level currently served by IESCO (Scenario 2).
- e. The proposed new tariffs that will ensure collection of the estimated revenue requirements without any interclass subsidies or transfers while maintaining the currently applicable tariff structure (Scenario 1).
- f. The proposed new tariffs that will ensure collection of the estimated revenue requirements without any interclass subsidies or transfers while maintaining the currently applicable tariff structure classified by voltage level (Scenario 2).
- g. Volumetric tariff design for all customer classes currently serviced by IESCO (Scenario 1).
- h. Functionally unbundled volumetric tariff design for all customer classes currently served by IESCO (Scenario 1).
- i. Functionally unbundled volumetric tariff design for customer classes currently served by IESCO classified by voltage level (Scenario 2).
- j. Functionally unbundled volumetric tariff design with identified “Customer Charges” tariff design for all customer classes currently served by IESCO (Scenario 1).
- k. Functionally unbundled volumetric tariff design with identified “Customer Charges” tariff design for customer classes currently served by IESCO classified by voltage level (Scenario 2).



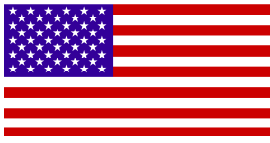
Currently, the Model version at hand is designed specifically for IESCO but can be used with some modifications for other Ex-WAPDA DISCO as well.

Scenario 1 is intended for use across the nine ex-WAPDA distribution companies. The minor variation observed in reporting the billing determinants and sales between the different companies may require marginally different templates to be prepared for each utility. **Scenario 2** is also intended to be used across the nine ex-WAPDA distribution companies, but with some modifications. These modifications are related to variation of the composition of each voltage level within the same tariff schedule. As will be discussed later this variation is addressed empirically and the aggregation of each voltage level will be determined accordingly. This variation will cause variation in some worksheets in Scenario 2, particularly in Groups A, D and E.

Although many components of **Scenario 1** and **2** are common, it is important to highlight that **Scenario 1** is the Cost of Service Study for the standard tariffs schedules, and **Scenario 2** is the Cost of Service Study for the tariff schedules classified by voltage level. The schematics and structure of the two templates are discussed further in Sections 0 and 6.

The results of the FACOS models provide the necessary components for several policy directions related to the provision of electricity service. FACOS results, however, will be complemented by the independent process currently performed by the different distribution companies to encompass the Fuel Charges Adjustments (FCA), referred as Fuel Price Adjustment (FPA) in Pakistan, into tariffs. These adjustments—pursuant to the provisions of Section 31(4) of the Regulation of Generation, Transmission and Distribution of Electricity Power Act 1997, (XL of 1997)—ensure that tariffs reflect any variations in the fuels charges on monthly basis.² With minor reference to how the power purchases are accounted for in the operating expenses in Section 7e, Section 8d discusses the connection between the FACOS model results and the independent FCA process.

² See NEPRA's decision in the matter of FCA for May 2012 for XWDISCOs and notification (<http://www.nepa.org.pk/Tariff/Ex-WAPDA%20DISCOS/2012/TRF-100%20MFPA%20May-2012%2011-07-2012%206053-70.PDF>). Date of visit: September 18, 2012.



4. Methodology and Approach

The methodology used to build the two FACOS scenarios follows very closely the standards used in the United States (US) and Canada as outlined in NARUC’s Electric Utility Cost Allocation Manual.³ The two scenarios perform the standard four steps encompassed in almost all Fully Allocated Cost Studies, namely:

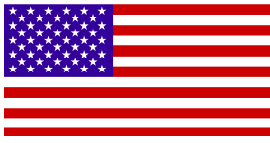
- “Accounts Identification”
- “Functionalization”
- “Classification”
- “Allocation”

The Test Year Concept

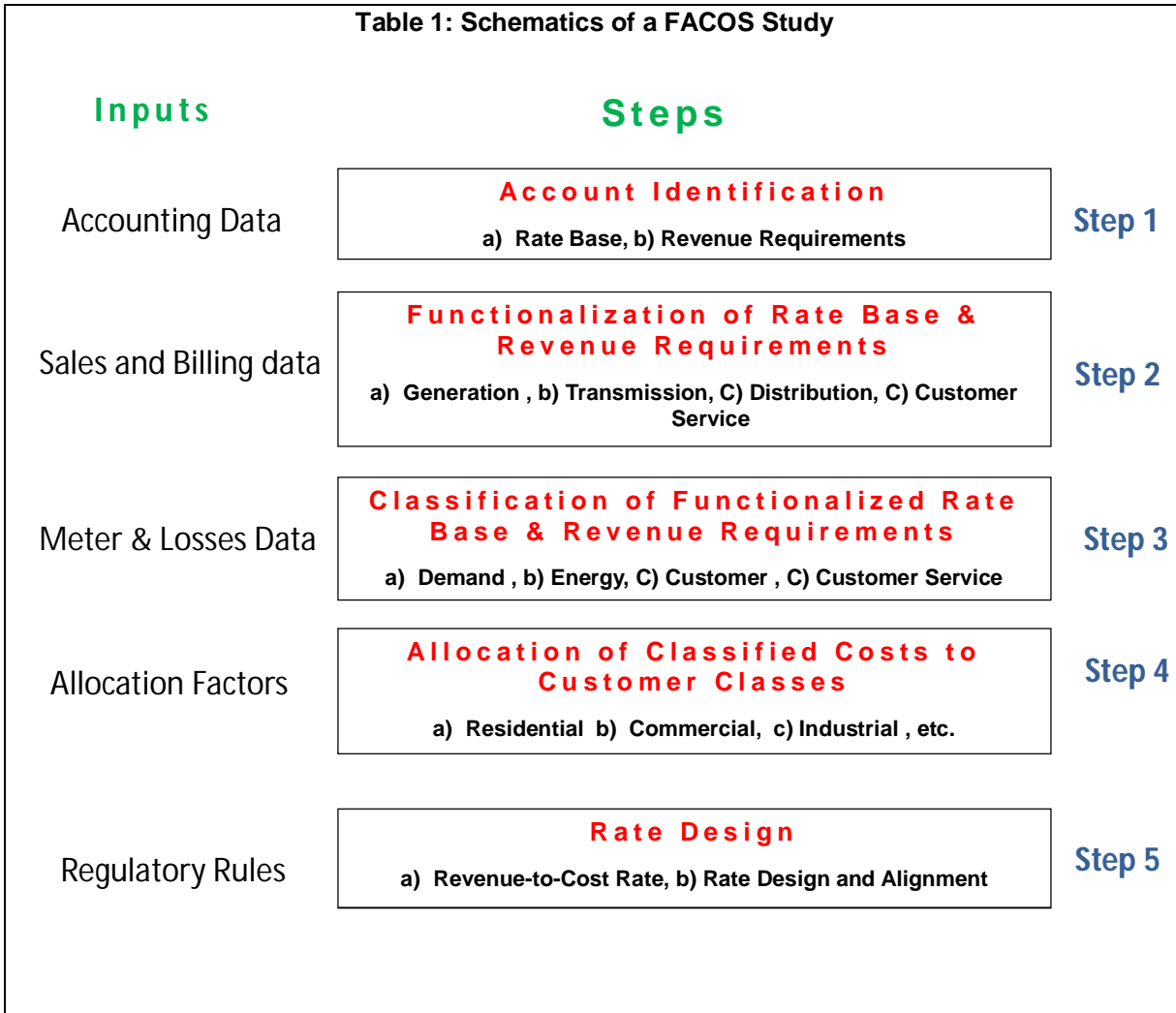
FACOS is an essential tool to establish rates. Therefore, the financial data for the fiscal year used in FACOS must be current and representative. The costs, revenues, and sales in the representative (test) year may be drawn from actual data, projected, or a mix of both. Given the stability of the results, the multi-year FACOS based on test year data can be a cost-effective mitigant to the considerably more expensive annual hearings of rate design and tariff setting. Although the concept of the test year is not used in this model, it is ready to incorporate it without any changes.

A fifth step, closely related to FACOS, but not an integral part of it, is “Rate Design”. **Table 1** demonstrates the five sequential steps of a FACOS Study and highlights the main types of inputs needed for its successful completion. The table also provides a general summary of the FACOS process. In general terms, the step of “Accounts Identification” compiles data for assets and expenses incurred to provide service in the period in question. In “Functionalization”, the costs of these assets and expenses are put in an order that reflects their function in providing service (generation, transmission, distribution, and customer service). In “Classification”, the costs are classified according to the reason of their

³ Electric Utility Cost Allocation Manual, NARUC, January 1992



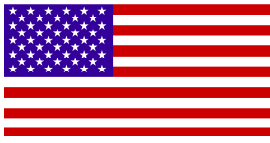
expense (demand, energy, and customer). Allocation of costs “distributes, or allocates” the classified costs to the different customer classes to determine the cost of service for each rate or customer class group. Finally, the cost incurred to provide service for each customer group is compared to the revenue accrued from the same class to determine their adequacy, i.e., whether the class pays for its service or not.



The details of these five steps are explained as follows:

a) Accounts Identification:

This step aims to identify the major components of the cost of service study i.e. the Rate Base (RB) and the Revenue Requirements (RR). The RB represents the investments that the utility undertook/will undertake during the year to provide the



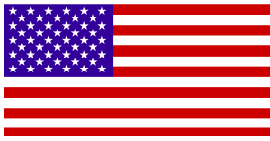
service, and the RR encompasses all the prudent expenditures it paid/will pay during the year for the service provided. The utility is entitled to the opportunity to earn a rate of return on its investments in plants and other equipment (the RB), and to recoup what has been spent to operate the system and provide service (the RR). A brief description of the two components is as follows:

i. The Rate Base:

The RB is the net book value of the assets used in providing the electricity service. In vertically integrated utilities, the RB is the summation of the net book value of the assets providing generation, transmission, distribution and customer service functions. In many jurisdictions, the RB may also include representation for Capital Work-in-Progress (CWIP), and working capital (WC). Of course, in restructured electricity markets, DISCOs do not own assets related to the functions of generation and transmission. Their requirements to serve their customers are purchased from their providers; their costs are part of the operating expenses explained below.

It is important to highlight that the correct identification of the rate base — properly functionalized to the main functions (generation, transmission, distribution, and customer service) is very important for two main reasons:

- a) Functionalized rate base—expressed as the net book value of the assets involved—is the representation of the capital cost to which the utility is allowed the opportunity (not the right, the opportunity) to earn a regulated rate of return.
- b) The pattern in which the rate base is structured can be very helpful to functionalize many components in the revenue requirements. Some costs are incurred in a joint manner to serve a general purpose (e.g., administrative expenses). As there is a need to determine the rationale for this common expenditure, the structure of rate base can provide the functionalization parameters. For example, if 40% of the utility's rate base is in



generation, 40% of the administrative expenses are related to the generation function, and so on.

Prudency of Investments and Cost

It is important to highlight that FACOS always assumes that these investments included in the RB and operating costs in the RR are prudent, used, and useful. Investments and operating costs that are deemed by the Regulator (e.g., NEPRA) to be imprudent are excluded from both the RB and RR. The utility will not be allowed the opportunity to earn a rate of return on the incurred investment or collect imprudent costs from its customers in the revenue requirements.

ii. The Revenue Requirements:

RR is effectively the cost of serving all customers that the utility is allowed the opportunity to recoup from its sales at the applicable rates. The simple formula classically used to explain its components is:

$$RR = E + D + T + [r*(V - D)]$$

Where

RR = Revenue requirement,

E = Operating expenses

D = Annual depreciation expense

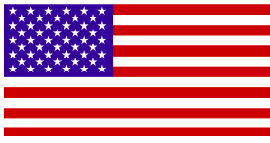
T = Taxes

V = Historical book value of plant & equipment in service

D = Accumulated depreciation – (“V – D”) is also known as the “net book value, or the Rate Base explained above)

r = Weighted average cost of capital, or the allowed rate of return.

It is noteworthy in restructured systems where the incumbent utility is only a distribution service company operating expenses may include all cost of purchased generation and transmission services from their providers.



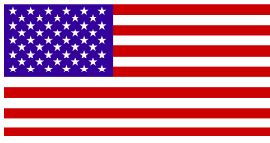
b) **Functionalization**: This step regroups the RB and RR according to their functions and sub-functions. The typical functions are:

- i. Production or Purchased Power: These are investments and costs associated with power generation and / or purchases. If the utility owns its generation, the related costs include the investment and expenses of thermal, hydro, renewable and other generating units. In restructured systems in which distribution companies purchase their generation needs, the costs associated to generation include the purchase of power from the wholesale market or the single purchaser as the case may be.⁴ In some cases, the cost of purchased power may include the cost of its delivery (i.e., transmission and ancillary services). An accurate FACOS, however, should unbundle this cost independently from generation for more accurate determination of cost responsibility (allocation).
- ii. Transmission or Purchased Transmission Service: These are investments and costs associated with the transmission and delivery of bulk generation to the utility's system. In vertically integrated systems, it is common to group all investments and expenses from the high side of the switchyards⁵ in the generation stations to the primary side of the various substations delivering transmitted power to the utility for distribution. Ancillary services are usually part of the transmission service cost. Ancillary services are: "those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's System in accordance with Good Utility Practices"⁶. Examples of the ancillary services include "Scheduling", "System Control and Dispatch

⁴ Some utilities may purchase power from co-generators inside their service territory. Such costs must be included in "Generation."

⁵ The switchyard is a transformer inside the generation station fence that steps up the generated electricity from the different units in the station from its generated voltage level to the required transmission voltage level. The generation station assumes the responsibility for the losses of this transformer.

⁶ See FERC Pro Forma Open Access Transmission Tariff (RM05-17-2003 & RM05-25,2003) at Sheet 10. <http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf> (date of visit: March 18, 2012).



Service”, “Reactive Supply and Voltage Control”, “Regulation and Frequency Response”, “Energy Imbalance Service”, and “Operating Reserve”.⁷

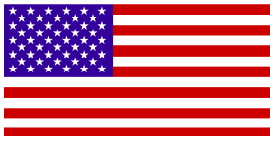
- iii. Distribution: These are investments and costs associated with the radial distribution system that connects the customers to the transmission system. Because this part of the system serves customer groups that may, or may not, use the entire distribution network, it is further sub-functionalized so that customers served at the primary distribution voltage are not held responsible for investments and costs associated with serving customers at the secondary distribution system. A typical sub-functionalization of the distribution system and expenses include the following:
 - a. Primary
 - b. Transformer
 - c. Secondary
- iv. Customer Service: These are investments and expenses related to providing the service drop, meter, meter reading, billing and collection, and customer information service.
- v. Administrative & General: These are investments and expenses related to management costs, administrative buildings and other assets and activities that cannot be directly assigned to other major cost functions.

c) **Classification of Investments and**

Expenses: Classification of functionalized RB and RR is an essential step in assigning responsibility for the component of the service being provided. For example, some investments and expenses are incurred to meet a certain level of demand (measured in Megawatt) at its peak. These demand-related investments and expenses should be the responsibility of those customer groups whose consumption patterns caused the peak to occur in proportion to their contribution. Similarly, energy-related

Some of the costs in the “Distribution” function are incurred exclusively in proportion to the demand level, some exclusively in proportion to the number of customers, and some to both.

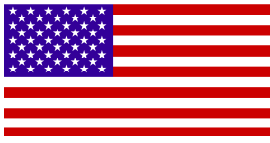
⁷ A good reference that exposes the evolution of Ancillary Services with the advent of restructuring in the US could be found in http://www.consultkirby.com/files/con426_Ancillary_Services.pdf.



investments and expenses (measured in megawatt-hour) should be the responsibility of those customer groups whose consumption pattern caused these to occur in proportion to their contribution. In addition to “Demand” and “Energy”, investments and expenses are also classified under a third category, namely “Customer”. These are investments and expenses incurred primarily in proportion to the number of customers served.

Classification of investments and expenses has followed certain practices that usually vary with their “Function.” For example, investments and expenses related to the Generation / Power Purchase function are classified as both “Energy” and “Demand”. Investments and expenses related to transmission—almost always—are classified as “Demand” given that the transmission system and its operations were / are sized to the peak demand level of all customer classes, rather than to their energy use. Investments and expenses for the “Distribution” function are classified either to “Demand” or “Customer”, or to both (i.e., “Demand” and “Customer”). Some of the costs in the “Distribution” function are incurred exclusively in proportion to the demand level, some exclusively in proportion to the number of customers, and some to both. Finally, classification of investments and expenses related to the functions of Customer Service and Administrative and General is, classified exclusively to “Customer”. The successful functional classification of investments and expenses will result in three pools of funds for allocation in the third step (“Allocation”) to the different customer classes. They are:

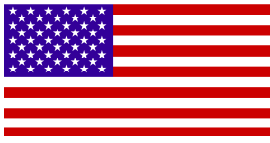
- Demand-Related Cost: This is the summation of the different demand related components from the “Generation / Power Purchase” function, the “Transmission” function, the portion related to demand in the distribution investments, and expenses.
- Energy-Related Cost: This is the summation of the different energy-related components from the “Generation / Power Purchase” function.
- Customer-Related Cost: This is the summation of the different customer-related components from the “Distribution” function and from all of Customer Services and Administrative & General.



d) **Allocation of Costs:** The methodology to allocate the different types of functionally classified costs to the different customer classes will differ with the type of function. Costs related to “Generation / Power Purchase”—now divided into costs classified to “Energy” and other classified to “Demand”—will be allocated to different customer classes according to “allocation factors” that reflect their contribution to energy and demand usage. For example, residential customers that use 40% of the IESCO total energy sales per annum must be responsible for 40% of all related costs to energy. Commercial customers use 30% of IESCO’s total energy sales must be allocated 30% of IESCO’s total energy related costs, and so on. Allocation of the “Generation / Power Purchase” function demand-related costs will use allocation factors that reflect the class responsibility during the utility’s system peak. In many cases, the contribution to the coincident peak of utility in a single point of time (1CP) in the year is used to arrive at a fair, just, and reasonable allocation factor. An example of the 1CP is demonstrated in **Table 2** in which the *hypothetical* contribution of each customer class in IESCO’s annual peak is measured in megawatt (MW). The table indicates that in this example the 1CP of 1,454 MW was registered on May 19 at 1400 hours. At that hour, the residential class taking service at A1 were responsible for 840 MW, the commercial at A2 for 198 MW, and the remainder of the other classes at rate schedules B, C, D, E, G, H and K are responsible for 416 MW. It follows that the residential customers are responsible for 57.8% of the costs associated with providing this level of demand, while the commercial customers are responsible for 13.6% and so on. The allocation factors for the generation-demand costs to all customer classes are demonstrated in **Table 3**. It is noteworthy that 1CP allocation factors are commonly used to allocate transmission-related costs to different customer classes given that 100% of the investments and expenses in this function are classified as “Demand”.

The average contribution to the 12 monthly coincident peaks is another common approach to arrive at a fair allocation of the generation-demand. One criticism of 1CP is that it is not really fair and reasonable because it assigns cost responsibility according to the class’

It is noteworthy that 1CP allocation factors are commonly used to allocate the transmission related costs to different customer classes given that 100% of the investments and expenses in this function are classified to demand.



demand in only one hour from 8,760 hours of the year. A customer class, which regularly uses the system, but makes very little contribution to the system's peak during that one peak hour in the year will assume very little responsibility. The 12CP addresses this concern through taking the average contribution of the 12 monthly peaks in the year. In such an eventuality, **Table 3** demonstrates an example in which residential customers will be responsible for 55.9% of the relevant Generation / Power Purchase demand costs rather than 57.8% using the 1CP allocation factor. Variations off the 12CP allocation factors approach are often seen in the various FACOS studies. Examples include 6CP for the average contribution in the three peak winter months and the three peak summer months. In a system in which generation capacity is scarce in the summer period, weighted CPs in which the class contribution in the summer months will be weighted higher than those of the winter months.

The allocation of the functionally classified distribution demand costs follows the same rationale above, but at the appropriate voltage level. The relative shares of each customer class at the relevant voltage level (i.e., primary, transformer, secondary) are used for allocation. Examples of such allocation factors could be followed from Worksheets D1.3 in Scenario 1. Finally, some costs are directly allocated to specific customer classes as the costs were incurred entirely because of their use. A classic example is all costs related to street lighting.

Table 2: Example of the Coincident Peak Demand in MW (at Meter)

Customer Class	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average 12 CP	1CP
Tariff: Residential- A1	696	657	618	580	564	541	518	502	464	448	840	798	602	840
Tariff: Commercial-A2	170	160	151	127	123	118	113	110	101	98	198	189	138	198
Tariff: Industrial-B1	13	12	11	9	9	9	8	8	7	7	15	14	10	15
Tariff: Industrial-B2	50	48	45	42	41	39	38	36	34	33	66	65	45	66
Tariff: Industrial-B3	23	21	20	19	18	18	17	16	15	15	25	24	19	25
Tariff: Industrial-B4	66	66	66	59	59	59	59	59	59	59	69	66	62	69
Tariff: Bulk Supply-C1	12	11	11	9	9	8	8	8	7	7	14	13	10	14
Tariff: Bulk Supply-C2	56	52	49	46	45	43	41	40	37	36	59	56	47	59
Tariff: Bulk Supply-C3	30	30	30	30	30	30	30	30	30	30	32	30	30	32
Tariff: Agriculture D-1	14	13	12	11	11	11	10	10	9	9	15	14	12	15
Tariff: Temporary Service- E	2	2	2	2	2	2	2	2	2	2	3	3	2	3
Tariff: Public Lighting-G	15	15	14	13	12	12	11	11	10	10	17	16	13	17
Tariff: Residential Colony-H	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tariff: Azad Jammu & Kashmir (AJK) - K	51	48	45	42	41	40	38	37	34	33	55	53	43	55
Tariff: Rawat Lab-K2	43	43	43	43	43	43	43	43	43	43	45	43	43	45
Total	1,240	1,179	1,118	1,033	1,009	973	937	913	853	829	1,454	1,383	1,077	1,454
Date	1-Jul	2-Aug	3-Sep	5-Oct	6-Nov	8-Dec	9-Jan	10-Feb	13-Mar	14-Apr	19-May	17-Jun		
Hour	15:00	14:00	16:00	11:00	14:30	16:00	15:30	14:00	16:00	15:30	14:00	16:00		

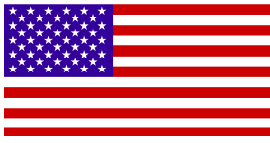
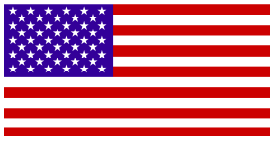


Table 3: Example of the Percentage Contribution to the Coincident Peak Demand (at Meter)

Customer Class	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Average 12 CP	1CP
Tariff: Residential- A1	0.561	0.557	0.553	0.561	0.559	0.556	0.553	0.551	0.544	0.541	0.578	0.577	0.559	0.578
Tariff: Commercial-A2	0.137	0.136	0.135	0.123	0.122	0.121	0.121	0.120	0.119	0.118	0.136	0.136	0.128	0.136
Tariff: Industrial-B1	0.010	0.010	0.010	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.010	0.010	0.009	0.010
Tariff: Industrial-B2	0.041	0.040	0.040	0.041	0.041	0.040	0.040	0.040	0.039	0.039	0.045	0.047	0.041	0.045
Tariff: Industrial-B3	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.017	0.017	0.018	0.017
Tariff: Industrial-B4	0.053	0.056	0.059	0.057	0.058	0.061	0.063	0.065	0.069	0.071	0.048	0.048	0.058	0.048
Tariff: Bulk Supply-C1	0.010	0.010	0.010	0.009	0.009	0.009	0.009	0.008	0.008	0.008	0.010	0.010	0.009	0.010
Tariff: Bulk Supply-C2	0.045	0.045	0.044	0.045	0.045	0.044	0.044	0.044	0.043	0.043	0.040	0.040	0.043	0.040
Tariff: Bulk Supply-C3	0.024	0.026	0.027	0.029	0.030	0.031	0.032	0.033	0.035	0.037	0.022	0.022	0.028	0.022
Tariff: Agriculture D-1	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.010	0.010	0.011	0.010
Tariff: Temporary Service- E	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Tariff: Public Lighting-G	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012	0.012
Tariff: Residential Colony-H	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tariff: Azad Jammu & Kashmir (AJK) - K	0.041	0.041	0.041	0.041	0.041	0.041	0.040	0.040	0.040	0.040	0.038	0.038	0.040	0.038
Tariff: Rawat Lab-K2	0.034	0.036	0.038	0.041	0.042	0.044	0.046	0.047	0.050	0.052	0.031	0.031	0.040	0.031
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

e) **Rate Design:** Once the allocated costs for each customer class are determined, these costs will be compared to the revenue from each customer class based on the latest NEPRA-determined tariffs. The comparison between the revenues based on NEPRA-determined tariffs to the cost of providing service to the respective customer class will produce a “revenue-to-cost” ratio (R/C). R/C of unity indicates that such customer class pays the embedded cost of its service; while less than unity indicates that this class is a recipient of a subsidy. Revenue-to-cost ratios greater than unity is an indication that such class not only pays its cost of service but also pays a portion of the cost of serving other customer classes, i.e. it is providing subsidy to other category(ies).

R/C is a measure of the cost of service recovery level to identify any imbalance between the cost of serving a customer class and the revenue accrued from it. This imbalance has to be addressed in the rate design stage to ensure that tariffs are free of inter- and intra-class subsidies. An example of the R/C for some selected utilities are demonstrated in **Table 4**. Residential customers in New Brunswick Hydro pay less than the cost of their service as their R/C ratio is only 0.86. There is an interclass subsidy from the commercial and the industrial customers who pay more than the cost

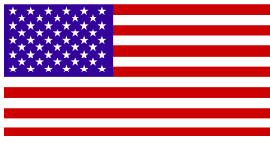


of their service given that their R/C are greater than unity. It is also clear that most of this interclass subsidy comes from the commercial class with little provided by industrial customers. Of course, with such data available, representatives for the commercial customers may challenge this interclass subsidy in any upcoming rate setting hearing proceeding.

Table 4: Revenue-to-Cost Ratios at Selected Utilities

	BCHydro ¹	New Brunswick Hydro ²	Manitoba Hydro ³
Residential	0.91	0.86	0.97
Commercial	1.08	1.15	1.01
Industrial	1.04	1.02	1.03
Agriculture	1.43	na	na

Sources: 1) BC Hydro Fully Allocated Cost of Service Study, 1994. 2) <http://www.gnb.ca/0085/electric/elec2000.htm>, 3) Manitoba Hydro, Cost of service Study, Overview, recommended revenue-to-cost ratios. P. 6



5. The Rationale for Scenario 1 and Scenario 2

The FACOS for IESCO consists of two Scenarios (Scenario 1 and 2) that are logically and structurally identical. The two scenarios differ in their representation of the different customer classes in IESCO. Scenario 1 estimates the cost of providing service to the standard existing customer classes, which are A1, A2, B, C, D, E, G, H and K. Scenario 2 estimates the cost of providing service to customer classes classified by distribution voltage level, which are those served at 0.2KV, 0.4KV, 11KV and 66KV/132KV. The standard customer class composition and that classified by the voltage levels is shown in Table 5.

The composition of the different customer classes by voltage level in **Scenario 2** follows the characterization of the distribution system in IESCO. As other companies may differ in their customer-class composition within each voltage level, **Scenario 2** may require some changes in order to be applicable across the other eight ex-WAPDA distribution companies. The changes will be in Worksheets **A2.1, A2.2, A2.3, A2.4, A2.5** as well as in **D2.1, D2.2, D2.3, D2.4, D2.5, E2.1, E2.2, E2.3, E2.4** and **E2.5**. Once the customer class composition is determined for each voltage level, **Scenario 2** is designed to reflect these changes on the other different components of FACOS in orderly and efficient manners. On the other hand, because of the commonality of the composition of the different customer classes in all ex-WAPDA companies, **Scenario 1** is transportable across DISCOs with relatively little changes.

The two scenarios for the Cost of Service Study will give the user flexibility to communicate slightly different results to policy makers. It is possible that policy makers may not accept different adjustment rates for tariffs within the same class. For example, Scenario 1 may suggest a specific rate of increase (or decrease) to be applied on all residential customer classes being supplied electricity at a certain voltage level. Scenario 2 is likely to suggest a specific rate of increase (or decrease) to be applied on A1a (residential customers less than 5 kW) that is different to that applicable on the residential customers taking services at A1b schedules (residential loads of 5 kW TOU). Either approach will ensure that the utility will have the opportunity to collect the same total cost of serving its customers.

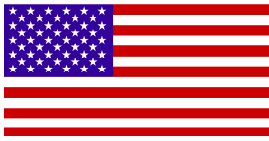
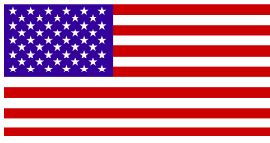


Table 5: Structure of Tariff Classes in Scenario 1 and Scenario 2

Scenario 1	Scenario 2			
	Voltage Level Classification			
	132/66	11kV	0.4kV	0.2 kV
A1 (Residential)	B4 (Industrial at 66 kV and above)	B3 (Industrial – All Loads up to 5 MW at 11kV)	A1b (Residential load 5kW TOU)	A1a (Residential -- Loads less than 5kW)
A2 (General)	C3a (Single Point Supply at 66 kV & Above)	C2a (Single Point Supply at 11 kV up to 5 MW)	A2b (Commercial load 5kW & above)	A2a (Commercial – Loads less than 5kW)
B (Industrial)	C3b (Single Point Supply at 66 kV & Above TOU)	C2b (Single Point Supply at 11 kV up to 5 MW - TOU)	A2c (Commercial load TOU)	B1a (Industrial up to 25 kW (at 400/230 Volts)
C (Single Point Supply)		K1 (AK)	B1b (Industrial up to 25kW)	C1a (Single Point at 400/230 less than 5 kW)
D (Agricultural)		K2 (Re wet Lab - TOU)	B2a (Industrial exceeding 35-500 kW at 400 kV)	D1a (SCRAP & Agricultural less than
E (Temporary Supply)		H (Residential Colonies)	B2b (Industrial exceeding 35-500 kW at 400 kV – TOU)	D2 (Agricultural Tube wells)
G (Public Lighting)			C1b (Single Point Supply 5kW & up to 500kW)	
H (Residential Colonies)			C1c (Single Point Supply at 11kV up to 500 kW TOU)	
K (Special Contracts)			D1b (SCRAP & Agricultural 5 kW & above)	
			G (Public Lighting)	

Source: Appendix 1

TOU = Time of Use

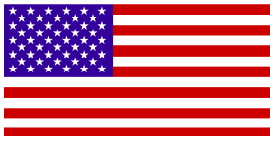


6. Structure and Standards of the Scenarios

Scenarios 1 and 2 are contained within a single Microsoft *Excel 2010* file by the name of *FACOS_Islamabad.xlsx*. The two scenarios are composed of different worksheets clustered in five different groups (**Groups A through E**) plus supporting worksheets. The two scenarios are basically dependent on four data input worksheets (**Input Sheets 1 through 4**) that facilitate data entry for the entire model. Furthermore, there are two worksheets (**Decision1** and **Decision 2**) that represent several decision points to be made by the user. These sheets offer considerable optionality to the user to comply with regulatory directives, and what-if analysis. Finally, there is a group of **Reference Worksheets** which are IESCO-specific. The structure of the model with its two scenarios is presented in **Table 6**.

The model is structured sequentially, that is, a) work on **Scenario 1** has to be completed before approaching **Scenario 2**, and b) work on **Group A** has to be completed before **Group B** and so on. The structure and composition of the worksheets of both scenarios are demonstrated in Table 6. A brief description of the different groups follows.

- a. **Decision 1 & 2**: Worksheets Decision 1 and Decision 2 are dedicated to the determination of some functional values that affect a) the calculation of both RB and RR (**Decision 1**), and b) the classification of distribution assets (**Decision 2**). For example, for the functional values in **Decision 1**, include the allowed regulated rate of return, the inclusion / exclusion of government subsidy as a component of RR, the interest rate applicable on short-term financing. **Decision 2** is dedicated to the classification ratios of the functionalized distribution assets to “Demand” and “Customer”.
- b. **Input Worksheets 1, 2, 3, and 4**: These sheets are the only four sheets that the user will need to populate for the model to provide the deliverables outlined in 0 above. The data inputs are related to sales, financial inputs, load data, and current applicable tariffs.
- c. **Group A**: Worksheets A1.1 to A1.11 compile the necessary data for sales and billing determinants for the test or financial year for **Scenario 1** following the standard



customer class classification. Worksheets A2.1 to A2.5 pertain to **Scenario 2** and are linked to Worksheets A1.1 to A1.11. These worksheets compile the necessary data for sales and billing determinants for the test / financial year classified by voltage level as demonstrated in Table 5.

- d. **Group B:** This group is common for both **Scenario 1** and **Scenario 2**. Worksheets B1 to B3 calculate the **classified RB** for the test / financial year.
- e. **Group C:** This group is also common for both **Scenario 1** and **Scenario 2**. Worksheets C1 to C3 calculate the **classified RR** for the test / financial year.
- f. **Group D:** For **Scenario 1**, worksheets D1.1 to D1.5 are dedicated to **Cost Allocation** for the functionally classified RR, following the standard customer class classification. For **Scenario 2**, worksheets D2.1 to D2.5 are dedicated to cost allocation for the functionally classified RR for each customer group classified by voltage level.
- g. **Group E:** For **Scenario 1**, Worksheets E1.1 to E1.5 calculate the **R/Cs** for the different customers following the standard customer class classification, provide the proposed structure of tariffs that would offer the utility the opportunity to collect the estimated revenue requirements, and demonstrate the preliminary volumetric and functionally unbundled Rate Designs. For **Scenario 2**, Worksheets E2.1 to E2.5 provide the same output for the different customers following the distribution voltage level classification.

The standards used in the template are summed as follows:

- i. The template uses and complies with the Standard Regulatory Accounts for Distribution Companies as determined by NEPRA.⁸ It is noteworthy that this system was found to be extremely close (possibly identical, at least as far as “account coding” is concerned) to that of the “Uniform System of Accounts Prescribed for Public Utilities And Licensees Subject to the Provision of the Federal Power Act in the US”.⁹
- ii. The accounting treatment of various technical questions pertaining to the determination of the RB or RR (e.g., working capital, the treatment of CWIP) followed

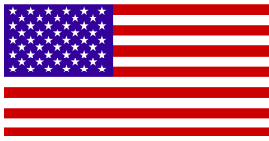
⁸ See part 3, 3-1 in <http://www.nepa.org.pk/legislation.htm>

⁹ Visit <http://cfr.vlex.com/source/code-federal-regulations-conservation-power-water-resources-1067/page/15>

Date of visit: August 24, 2011.

Also <http://ecfr.gpoaccess.gov/cgi/t/text/text->

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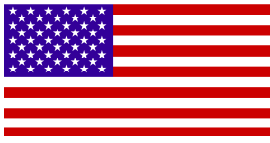


the industry standards in the US and Canada which are effectively listed in “Accounting for Public Utilities”.¹⁰ Notwithstanding this observation, Scenario 1 and Scenario 2 are designed to accommodate NEPRAs regulatory directives regarding the treatment of the various components in the RB and RR.

Table 6: Composition of Scenarios 1 and 2

WORKSHEETS	SCENARIO 1	SCENARIO 2
The Team	The Team	
Decision 1	Decision 1	
Decision 2	Decision 2	
Input One	Data for Rate Base and Revenue Requirement	
Input Two	Input for Billing Data	
Input Three	Load Data and Losses	
Input Four	NEPRA Determined Tariff By Standard Customer Class Classification	
	INDEX-A (STEP 1)	INDEX-A (STEP 1)
*A1.1	Sales-- Residential (A1)	*A2.1 Sales to Customer Classes at 0.2kV
*A1.2	Sales -- Commercial (A2)	*A2.2 Sales to Customer Classes at 0.4 kV
*A1.3	Sales -- Industrial (B)	*A2.3 Sales to Customer Classes at 11kV
*A1.4	Sales -- Single Point Supply (C)	*A2.4 Sales to Customer Classes at 132/66kV
*A1.5	Sales --Agricultural (D)	A2.5 Total Sales by Voltage Classification
*A1.6	Sales--Temporary Supply (E)	
*A1.7	Sales--Public Lighting (G)	
*A1.8	Sales -- Residential Colonies (H)	
*A1.9	Sales -- A,KK -- K	*Hidden Sheets
*A1.10	Sales--Rawat Lab	
A1.11	Total Consolidated Billing data	
	INDEX-B (STEP 2)	
B1	Calculation of Functionally Classified Rate Base in Test Year	
B2	Calculation of Construction Work in Progress in Test year	
B3	Minimum System Classification Coefficients	
	INDEX-C (STEP 3)	
C1	Functional Classification and Calculation of Operating Income	
C2	Revenue Requirements	
C3	Classification of Functionalized Operating Income	
	INDEX-D (STEP 4)	INDEX-D (STEP 4)
D1.1	Allocation of Revenue Requirement by Standard Customer Class Classification	D2.1 Allocation of Revenue Requirement by Voltage Level Customer Class Classification
D1.2	Percentage Summary of Allocation Factors by Standard Customer Class Classification	D2.2 Percentage Summary of Allocation Factors by Voltage Level Customer Class Classification
D1.3	Energy Allocation Factors by Standard Customer Class Classification	D2.3 Energy Allocation Factors by Voltage Level Customer Class Classification
D1.4	Demand Allocation Factors by Standard Customer Class Classification	D2.4 Demand Allocation Factors by Voltage Level Customer Class Classification
D1.5	Customer Allocation Factors by Standard Customer Class Classification	D2.5 Customer Allocation Factors by Voltage Level Customer Class Classification
	INDEX-E (Results)	INDEX-E (Results)
E1.1	Revenue to Cost Ratios by Standard Customer Class Classification	E2.1 Revenue to Cost Ratios by Voltage Level Customer Class Classification
E1.2	Current and CoS Rate by Standard Customer Class Classification	E2.2 Current and CoS Rate by Voltage Level Customer Class Classification
E1.3	Volumetric Tariff by Standard Customer Class Classification	E2.3 Volumetric Tariff by Voltage Level Customer Class Classification
E1.4	Unbundled Volumetric Tariffs by Standard Customer Class Classification	E2.4 Unbundled Volumetric Tariffs by Voltage Level Customer Class Classification
E1.5	Unbundled Volumetric and Customer Charges Tariffs by Standard Customer Class	E2.5 Unbundled Volumetric and Customer Charges Tariffs by Voltage Level Customer Class
	TARIFF DESIGN	
Existing Tariff	Existing Tariff Categories as per Existing Customer classification	
Alternate Tariff	Recommended Tariff for Alternate Customer Classification	
Voltage Tariff	Voltage Based Tariff for Existing Customer Classification	

¹⁰See Hahne R. & Aliff, G, “Accounting for Public Utilities”, Matthew Bender & Co, LexisNexis Group, November 2010. See <http://www.lexisnexis.com/store/catalog/booktemplate/productdetail.jsp?pageName=relatedProducts&prodId=10154>



7. The Fully Allocated Cost of Service Study – Step-by-Step

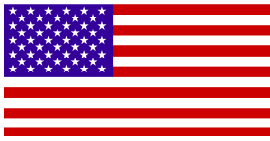
This section is a systematic walk through **Scenarios 1** and **2**. It is helpful to remember that it consists of five different groups (**Groups A** through **E**). **Group A** is dedicated to compiling monthly sales, billings, and revenues data from the different customer classes. **Group B** pertains to the determination and classification of the Rate Base. **Group C** pertains to determination and classification of the Revenue Requirements. **Group D** pertains to the allocation of the functionally classified Revenue Requirements to the different customer classes, and **Group E** to Rate Design.

As highlighted earlier, the FACOS model is structured sequentially, that is, work on **Group A** has to be completed before **Group B**, and so on. This order is as follows:

a. Step One – Decision 1 and Decision 2 Worksheets

These two worksheets assist the user to determine options from dropdown menus among alternative methodologies and values. Worksheet **Decision 1** provides alternative values and approaches to the following decision points:

1. What is the applicable allowed rate of return IESCO is permitted to collect? The chosen value will affect the calculation of the revenue requirements in Worksheet **C2**.
2. Should CWIP be a part of the RB or not?
3. Should the utility be allowed to include working capital in the rate base or not. And, if permitted, what methodology should be used. The chosen approach will affect the values of the RB and the RR in Worksheets **C3** and **B3**.
4. If working capital is not permitted to be in the RB, but its cost is permitted to be included at the current applicable rate of return on short term lending, what would be the appropriate rate of return? The chosen value will affect the revenue requirement calculation in Worksheet C1.



5. What is the most relevant methodology to allocate the functionally classified Generation / Power Purchase demand when the different allocation factors are determined for allocating the various functionally classified costs in Worksheets **D1.2, D1.3** for **Scenario 1** and **D2.2** and **D2.3** in Scenario 2?
6. What is the level of sales growth in case the base year is a projected year?
7. What would the amount of Prior Year Adjustment be, if any, for inclusion in the RR?

Worksheet Decision 2 also serves both scenarios and is fully dedicated to determining the most accurate approach to classify the functionalized distribution assets and costs between Demand and Customer in **Worksheet B3** and **Worksheet C3**. The rationale and methodology for the approach followed in Decision 2 are discussed further in Section 8.b.iii below. This worksheet calls on inputs drawn from the “Supporting Worksheets” located at the end of the templates.

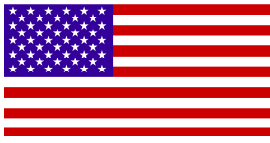
b. Step Two – Input Sheets One, Two, Three and Four

This group of Input Sheets is dedicated to data inputs for the model. These sheets are as follows:

1. **Input One**: This sheet is dedicated to all the financial inputs required to compile both the RB and RR and their sub-components of working capital and work-in-progress.
2. **Input Two**: This sheet is dedicated to compiling all sales and billing data for all customer classes currently served by IESCO.
3. **Input Three**: This sheet is dedicated to compiling all coincident and non-coincident peak load data and the data for energy and capacity losses for the model.
4. **Input Four**: This sheet is dedicated to compiling information on the tariffs currently determined by NEPRA for all customer classes served by IESCO.

c. Step Three – Sales and Billing Determinants – Group A:

As highlighted earlier, this group is dedicated to compiling the necessary data for monthly sales and billing determinants for the test or financial year. This group of



worksheets is auto-populated from **Input One Worksheet**. **Worksheets A1.1 to A1.11** pertain to **Scenario 1** (i.e., the standard customer class classification) and **A2.1 to A2.5** pertain to **Scenario 2** (i.e., classified by distribution voltage level). Worksheets **A1.1 to A1.10** compile the monthly data on a customer class-by customer class basis for the Test or Financial Year. **Worksheet A1.11** compiles the summary for all customer classes. Worksheets **A1.1 to A1.10** have been hidden in the model as the data from these is aggregated in **Worksheet A1.11** and from there it flows to the next set of sheets.

Worksheets A2.1 to A2.4 that pertain to Scenario 2 and will also be auto-loaded from **Worksheet Input One**. Worksheets **A2.1 to A2.4** have been hidden in the model as the data from these is aggregated in **Worksheet A2.5**.

Worksheet A2.5 provides the totals for all customer classes classified by the different distribution voltage levels, and will be the link worksheet to other groups (particularly Groups **D** and **E**).

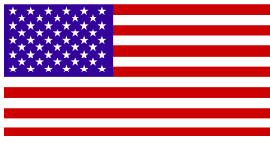
d. Step Four – Functionalization and Classification of the Rate Base – Group B

Worksheets B1 to B3 calculate the classified RB for the test / financial year.¹¹ The Rate Base is defined as the summation of:

1. Intangible Plant & Equipment (net of accumulated depreciation)
2. Distribution Plant & Equipment (net of accumulated depreciation)
3. General Plant & Equipment (net of accumulated depreciation)
4. Work in progress (if allowed by NEPRA)
5. Working Capital (if both are allowed by NEPRA)
6. Offsets like long-term customers' deposits (A/C D240090) and deferred credits & taxes

Again, all inputs necessary to populate Group B are provided in Worksheet Input One.

¹¹ RB for a DISCO relates to its status as a distribution company, thus does not include any assets that are related to the Generation and the Transmission functions. **Worksheet B3** highlights this observation in cells G9 and G10 that are dedicated to listing the RB for generation and distribution that are booked at zero value.

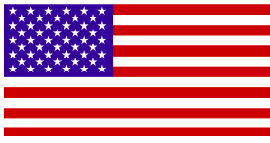


Worksheet B1 lists all the relevant accounts with their DRA and account numbers (as classified by NEPRA issued Uniform System of Accounts) in the range **B18:G152**.

- i. **B1 Worksheet** is dedicated to determining the RB for the utility in the base year. Entry of the end-of-year balances in Column “**B1**”**F** is largely facilitated by the strict adherence to the NEPRA line numbers listed in Column “**B1**”**C** which themselves are linked to the different DRAs in column “**B1**”**B**. For the current version, please ignore column “**B1**”**G** as it accounts for the possible existence of assets owned by the Utility but not involved in its regulatory function.
- ii. Please observe that **B1 Worksheet** demonstrates the additional functionalization (sub-functionalization) of the distribution RB to its subdivisions of Primary, Transformer, Secondary, Services, Meters, Street Lighting, Accounting Customers, and Sales Customers.
- iii. **B2 Worksheet** is dedicated to estimate the WC for IESCO in the test or financial year. The data entry of both 45-day and Balance Sheet approaches is governed by NEPRA line numbers and the relevant DRAs in the respective columns.
- iv. **Worksheet B3** is dedicated to classifying the Functionalized Distribution RB arrived at in **Worksheet B1**. The classification of these rate base items as “Demand”-related and “Customer”-related is discussed in detail in **Section 8.b below**, and is related to the discussion in **Worksheet Decision 2** above. The results of classifying these RB items will determine the rate base (in PKR).

e. **Step Five – The Revenue Requirements – Group C**

As highlighted earlier, Group C worksheets are dedicated to calculating the classified Operating Revenue and Revenue Requirements for the test year (or the fiscal year) for both **Scenario 1** and **Scenario 2**. The generic formulae discussed above (namely, $RR = E + D + T + [r*(V - D)]$) are effectively used as both templates (mainly through **Worksheet C1**) must compile data for operating expenses, depreciation, taxes, and



the allowed rate of return on the RB. If the currently billed revenue grants the utility the opportunity to recover the cost of providing service (including the regulated rate of return), there will be no adjustments to the current revenues level. If the current revenues are deficient, then the new RR level will increase.

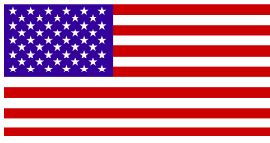
Table 7, which is actually Worksheet C2 of the model, lists all components of the revenue requirement. It is important to highlight that the “Allowed Rate of Return” is a policy variable that is determined in Worksheet “Decision 1”.

Table 7: Determination of the RR for the Test or the Fiscal Year*

Line No.	Description	Balance
1	Power Purchase Cost	PKR 85,248,593,577
2	DISTRIBUTION MARGIN	
A	Operation and Maintenance Expense	PKR 6,775,763,756
a)	Distribution Charges	PKR 0
b)	Maintenance Expense – Distribution Plant	PKR 584,942,552
c)	Maintenance Expense – General Plant	PKR 43,337,522
d)	Sales Expenses	PKR 4,815,888
e)	Billing and Collection	PKR 183,698,865
f)	Community Relations	PKR 0
g)	Administrative Expenses	PKR 5,958,968,929
h)	Inclusion of Working Capital in Revenue Requirement	PKR 0
B	Depreciation of Distribution Plant	PKR 1,983,060,455
C	Return on Rate Base	PKR 4,001,160,822
	GROSS DISTRIBUTION MARGIN	PKR 12,759,985,034
D	Less: Other Income	PKR 1,197,837,613
	NET DISTRIBUTION MARGIN	PKR 11,562,147,421
E	PRIOR YEAR ADJUSTMENTS	PKR 20,985,983,155
	TOTAL REVENUE REQUIRED	PKR 117,796,724,153

Source: See Worksheet C2.

C1 Worksheet compiles the different components of the Revenue Requirements. Following the NEPRA Line numbers listed in column “C1”C (which themselves are linked to the different DRAs in column “C1”B) should facilitate data entry considerably. The power purchases are bundled into “Energy Charges”, “Capacity Charges”, and “Other Charges. Fuel costs are not identified as a separate cost item; instead, they are

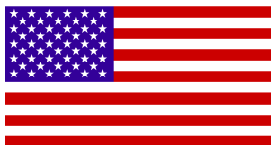


bundled within “Energy Charges”. Any process to track the changes in fuel cost into tariffs, e.g. the Fuel Charges Adjustment, has to be performed in a later stage in a process independent from FACOS.

- As highlighted earlier, the arrival at the RR for the test or financial year requires two inputs calculated in **Worksheet C2** and **Worksheet C3**. They are as follows:
 - i. **Worksheet C2** calculates the allowed return on the RB as previously determined in **Worksheet B1**. The allowed return on the RB is a policy directive for NEPRA to determine. **Worksheet Decision 1** provides the user with the option to determine the applicable rate in “**C2**”**J10**.
 - ii. **Worksheet C3** has a very similar function to Worksheet B3 discussed above, namely the Classification of Functionalized Revenue Requirement listed in Worksheet C1. The functionalization of the various operating expenses in column “C1”G is a straightforward exercise. Expenses related to “Generation / Power Purchase” (energy and demand) are functionalized, naturally, to the “Generation / Power Purchase” function. Similarly, expenses related to transmission are functionalized to that function. All other operating expenses are functionalized to the Distribution function.

f. **Step Six – Cost Allocation – Group D**

As highlighted earlier, **Worksheets D1.1 to D1.5** are dedicated to Cost Allocation for the functionally classified RR arrived at in **Worksheet C1** for **Scenario 1** to the different standard customer classes. Similarly, **Worksheets D2.1 to D2.5** are dedicated to the same function for **Scenario 2** classified by the different voltage levels. Both groups of worksheets are almost identical in logic and structure. In this step, each customer class will assume its responsibility in the functionally classified cost item.

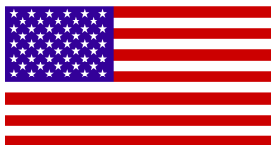


The allocation factor for each functionally classified cost item will vary following the nature of the cost component. For example, it is easy to allocate the generation cost classified to “Energy” to the different customer classes based on their relative share of energy consumption to the total energy consumed. Residential customers (or customers served on 0.2KV voltage level) who consumed 43% of the energy, should assume 43% of its costs and so on. The allocation of the functionally classified costs in both **Scenario 1** and **2** are as follows:

Table 8: Basis of Costs Allocation

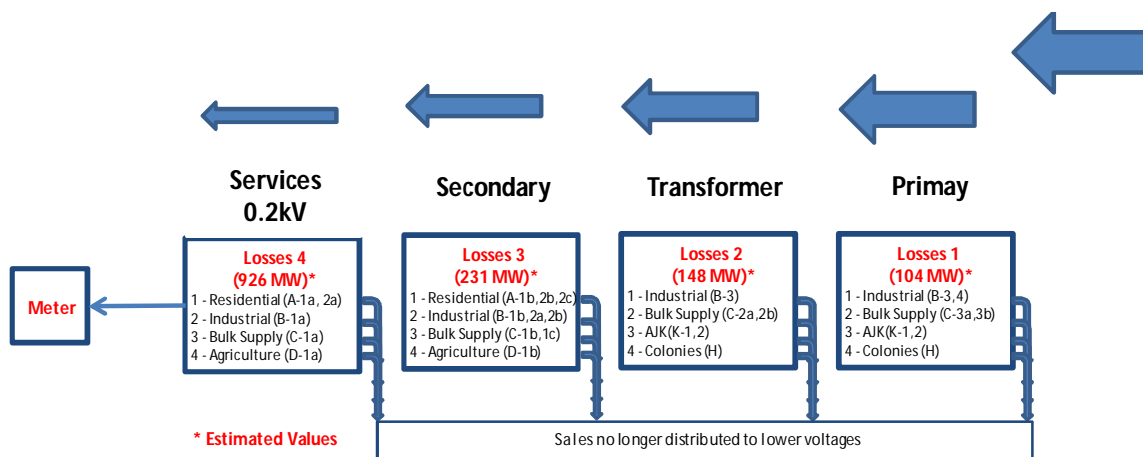
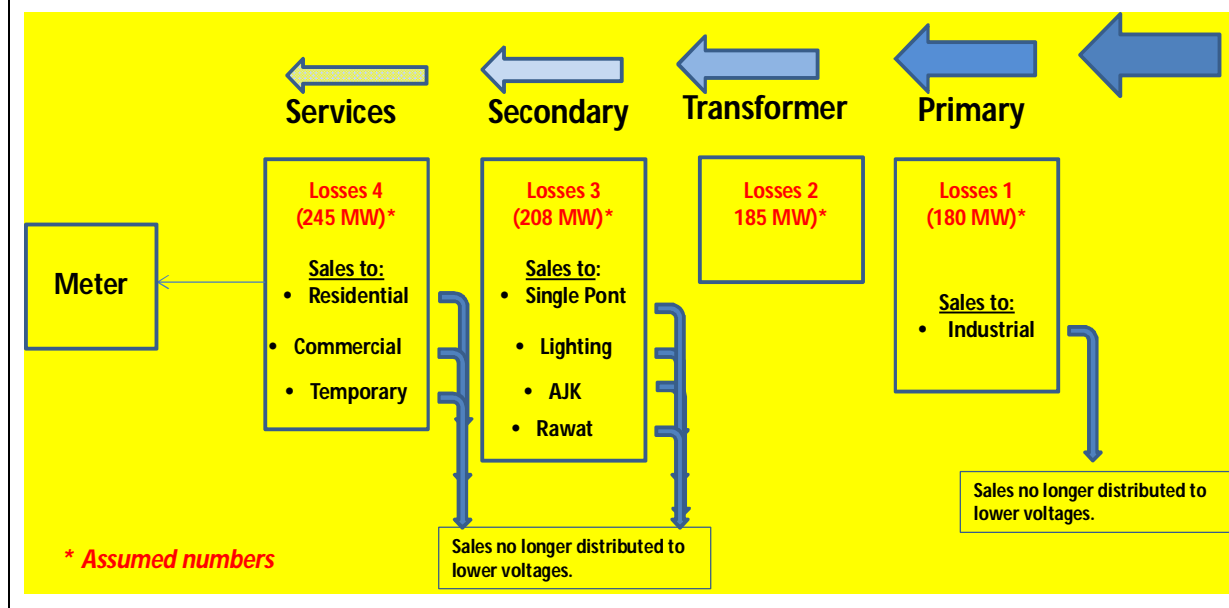
Cost Type	Allocation Basis			Remarks
	Demand	Energy	Customer	
1. Generation / Power Purchase				1CP or 12CP controllable from worksheet Decision 1 kWh Sales
➤ Capacity Charge	✓			
➤ Use of System – NTDC	✓			
➤ Energy Charges		✓		
2. Distribution Voltage Level Systems				1CP or 12CP for Demand related and Averaged No. of Customers for Customer services
➤ Primary (132KV/66KV)	✓		✓	
➤ Transformer – HT (11KV)	✓		✓	
➤ Secondary – LT (0.4KV)	✓		✓	
➤ Services (0.2KV)	✓		✓	
3. Meters			✓	Averaged No. of Customers
4. Street Lighting			✓	
5. Accounting			✓	
6. Customer Services			✓	

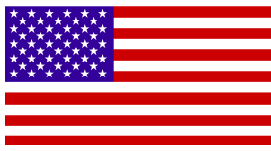
To explain the above allocation factors, it is important to understand how the two templates deal with demand and energy losses. As electricity is delivered at the common delivery points (CDPs) with the transmission system, it moves through the different voltage levels from “Primary”, to “Transformer”, to “Secondary”, then to “Services”. At each voltage level, the flow of electricity is reduced by: a) losses, and b) deliveries to customers served at that level. For example, the flow of electricity from “Primary” to “Transformer” in **Table 9** (which demonstrates the schematics of demand losses in an assumed period) indicates that at this voltage level, sales to large industrial customers and losses of 104 MW have taken place, and electricity delivered to the transformer is equal to what has been received from the transmission system minus sales to industrials and losses. At each voltage level, the



relative share of each customer class supplied at that level in both demand and energy sales increases. It increases because sales of energy and capacity diminishes as the service voltage is reduced. For example, residential sales may be 50% of total delivered energy and capacity at the primary level, however, it will be 85% or more at the meter as no other class but residential and, to a lesser extent, commercial, is served at that voltage level.

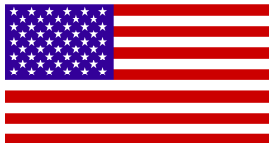
Table 9: Schematic of Demand Losses in an Assumed Period





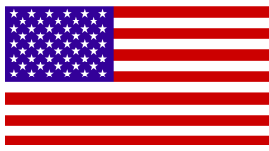
The following steps are recommended:

- i. Start with **Worksheet D1.5**. It consists of six tables that will help determine the customers' allocation factors (the same structure in **D2.5** for Scenario 2). These allocation factors are utilized in the subsequent stage to allocate the customer and meter-related costs to the different customer classes. Table 1 in **Worksheet D1.5** lists the number of customers, sales in kWh and revenues in PKR for all the different customer classes. It also calculates the relative weight of each class in the total customers, sales and revenues.
- ii. The relative weight of each customer class is useful to measure the class size in number of parameters (e.g. accounts, percentage of sales, etc.). However, it is rather "crude" in reflecting the class impact on providing the cost of its service. For example, costs associated with meter reading expenses cannot be simply divided by the number of customers as this approach, naturally, would overestimate the relative share of the residential class. The most common practice in the US is to use the relative cost of installed meters for each class as a proxy to allocate meter-related expenses to the different classes. For example, industrial customers who are limited in number, but with the most expensive meters, assume a larger share of meter and maintenance costs than by simply dividing the relative share of their numbers. Absent this information, the template weighted the different customer classes by the average size of each class. The same approach is applied to all other classes resulting in a more representative relative share in cost responsibility.
- iii. Further, tables 3, 4, 5 and 6 in **Worksheet D1.5** provide an important customer allocation factor that reflects the customer allocation factors by sub-function (voltage level). For example, at the primary voltage level, the utility is serving all their customers. As it moves down in voltage, the total number of customers at transformers is down because at that voltage level, the utility is no longer supplying industrial customers. As the company moves down to secondary voltage, then to services voltage, the company is serving only residential, commercial, and agricultural customers. Table 4 represents the relative weight of each customer class at the sub-function (voltage) level. The



numbers of customers at the meter level (to allocate the meter cost) is that of all customers at all voltage levels. Tables 5 and 6 repeat the same exercise, however for the adjusted average customer as explained above.

- iv. **Worksheet D1.4:** This is another important worksheet that consists of five tables. These tables compile data for coincident peak as well as determine the demand allocation factors after accounting for demand losses. Again, the same rationale is followed in **Worksheet D2.4** for Scenario 2.
- v. Table 2 in **Worksheet D1.4** calculates the demand loss allowance factors from data compiled at the different sub-functions (voltage levels). Table 3 expresses the demand losses in percentages. Table 4 utilizes these percentages to arrive at the class demand of each subcategory (voltage level) in the utility's 1CP, and Table 5 expresses each class responsibility into a percentage that could be used for allocation.
- vi. **Worksheet D1.3:** This worksheet (in four tables) repeats the same analysis performed in Worksheet D5, but for energy rather than capacity. Table 1 develops the energy loss allowance factor for each customer class at each voltage level. Table 2 expresses the energy loss allowance factors in percentages, Table 3 expresses the energy sales, inclusive of losses, for each customer class at each voltage level, and Table 4 demonstrates each class responsibility in sales into a percentage that could be used for allocation. The same rationale is followed in **Worksheet D2.3** for Scenario 2.
- vii. **Worksheet D1.2.:** This worksheet sums up the percentage share of different values of the allocation factors that will be used to allocate the functionally classified RR to each customer class. These percentages are used in Worksheet **D1.1** to allocate the different functionally classified RR totals into the different customer classes.
- viii. **Worksheet D1.1:** This worksheet provides the cost of serving each customer class after receiving their share in different cost components of the revenue requirement.



Worksheets D2.1 through D2.5 are identical in logic and structure to those in D1.1 through D1.5 but for the different customer groups classified by voltage level.

For example, Worksheet D2.5 is identical to D1.5, but structured for the different customer groups at various voltage levels. Similarly, Worksheet D2.4 is similar to D1.4, and so on.

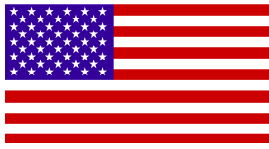
Table 10: Percentage Summary of Allocation Factors

Line No.		Voltage	Generation		Transmission	Distribution							
			Energy	Demand	Demand	Primary (132kV/66kV)		Transformers (HT Lines)		Secondary (LT Lines)		Services (Service Drop)	Meters
						Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Tariff: Residential-A1(a)	0.2kV	37.49%	57.93%	57.93%	57.93%	36.77%	62.08%	42.11%	69.36%	57.84%	90.97%	36.77%
2	Tariff: Residential- A1(b)	0.4kV	7.27%	2.97%	2.97%	2.97%	7.15%	3.18%	8.19%	3.56%	11.24%	0.00%	7.15%
3	Tariff: Commercial-A2(a)	0.2kV	3.31%	8.17%	8.17%	8.17%	3.25%	8.76%	3.72%	9.78%	5.11%	8.03%	3.25%
4	Tariff: Commercial- A2(b)	0.4kV	0.16%	0.44%	0.44%	0.44%	0.15%	0.48%	0.18%	0.53%	0.24%	0.00%	0.15%
5	Tariff: Commercial-A2(c)	0.4kV	7.62%	5.70%	5.70%	5.70%	7.50%	6.10%	8.58%	6.82%	11.79%	0.00%	7.50%
6	Tariff: Industrial-B1(a)	0.2kV	0.05%	0.16%	0.16%	0.16%	0.05%	0.17%	0.06%	0.19%	0.08%	0.12%	0.05%
7	Tariff: Industrial-B2(a)	0.4kV	0.14%	0.41%	0.41%	0.41%	0.14%	0.44%	0.16%	0.49%	0.22%	0.00%	0.14%
8	Tariff: Industrial-B1(b)	0.4kV	0.69%	0.73%	0.73%	0.73%	0.68%	0.78%	0.78%	0.87%	1.07%	0.00%	0.68%
9	Tariff: Industrial-B2(b)	0.4kV	4.61%	3.61%	3.61%	3.61%	4.53%	3.87%	5.19%	4.32%	7.13%	0.00%	4.53%
10	Tariff: Industrial-B3	11kV	5.62%	1.76%	1.76%	1.76%	5.69%	1.88%	6.51%	0.00%	0.00%	0.00%	5.69%
11	Tariff: Industrial-B4	132/66kV	9.51%	4.58%	4.58%	4.58%	10.24%	0.00%	0.00%	0.00%	0.00%	0.00%	10.24%
12	Tariff: Bulk Supply-C1(a)	0.2kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Tariff: Bulk Supply-C1(b)	0.4kV	0.10%	0.49%	0.49%	0.49%	0.10%	0.53%	0.11%	0.59%	0.15%	0.00%	0.10%
14	Tariff: Bulk Supply-C2(a)	11kV	1.30%	1.32%	1.32%	1.32%	1.32%	1.41%	1.51%	0.00%	0.00%	0.00%	1.32%
15	Tariff: Bulk Supply-C3(a)	132/66kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	Tariff: Bulk Supply-C1(c)	0.4kV	0.95%	0.51%	0.51%	0.51%	0.94%	0.55%	1.07%	0.62%	1.48%	0.00%	0.94%
17	Tariff: Bulk Supply-C2(b)	11kV	4.05%	2.80%	2.80%	2.80%	4.10%	3.00%	4.70%	0.00%	0.00%	0.00%	4.10%
18	Tariff: Bulk Supply-C3(b)	132/66kV	2.26%	2.10%	2.10%	2.10%	2.44%	0.00%	0.00%	0.00%	0.00%	0.00%	2.44%
19	Tariff: Agriculture D-1(a)	0.2kV	0.06%	0.16%	0.16%	0.16%	0.06%	0.17%	0.07%	0.19%	0.09%	0.14%	0.06%
20	Tariff: Agriculture D-2	0.2kV	0.08%	0.19%	0.19%	0.19%	0.07%	0.20%	0.08%	0.23%	0.12%	0.18%	0.07%
21	Tariff: Agriculture D-1(b)	0.4kV	1.00%	0.62%	0.62%	0.62%	0.99%	0.67%	1.13%	0.75%	1.55%	0.00%	0.99%
22	Tariff: Temporary Service -E-1(i)	0.2kV	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.02%	0.01%
23	Tariff: Temporary Service -E-1(ii)	0.2kV	0.22%	0.18%	0.18%	0.18%	0.21%	0.20%	0.24%	0.22%	0.33%	0.53%	0.21%
24	Tariff: Temporary Service -E-2	0.2kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25	Tariff: Public Lighting - G	0.4kV	0.99%	1.23%	1.23%	1.23%	0.97%	1.32%	1.12%	1.47%	1.53%	0.00%	0.97%
26	Tariff: Residential Colonies- H	11kV	0.05%	0.03%	0.03%	0.03%	0.05%	0.04%	0.06%	0.00%	0.00%	0.00%	0.05%
27	Tariff: Azad Jammu & Kashmir (AJK) - K1(i)	11kV	12.45%	3.89%	3.89%	3.89%	12.60%	4.16%	14.43%	0.00%	0.00%	0.00%	12.60%
28	Tariff: Azad Jammu & Kashmir (AJK) - K1(ii)	11kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Tariff: Rawat Lab-K2	11kV	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%
30	Total		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Worksheet D1.2

g. Step Seven – Revenue to Cost Ratios and Tariffs – Group E

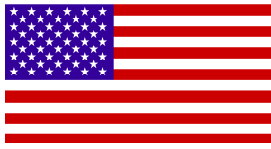
Group E—in five worksheets for Scenario 1 and another five for Scenario 2—provides the R/Cs, the proposed tariffs that would grant IESCO the opportunity to collect the revenue requirements at the current tariff designs, and other preliminary



rate structures. They are as follows (starting with Worksheets E1 to E5 for **Scenario 1**)

- **Worksheet E1.1** is an important policy-setting tool. It calculates the R/Cs for each customer class through comparisons between the revenues billed to customers to the class plus subsidy billed to the Government vis-à-vis the estimated allocated cost of service. Ratios greater than unity indicate that the class is contributing to the utility’s annual revenues more than the cost of its service, therefore granting subsidies to other classes. Ratios less than unity indicates that the class revenue does not cover the cost of its service, and is therefore receiving a subsidy. Ratios equal to unity indicate that the class revenues meet the cost of its service, and neither receives, nor grants a subsidy. The policy direction for rate design will benefit considerably from these ratios as they often determine whether tariffs of specific customer class will increase or decrease to bring the classes ratios closer to unity.
- **Worksheet E1.2:** This worksheet provides the proposed tariffs at the currently applicable design that would offer IESCO the opportunity to recover the revenue requirements. Each customer class—if its current tariffs are at an adequate level to ensure revenues equal to the cost associated to its service—should indicate a revenue to cost ratio of “one”. If the revenue to cost ratio is less than one (for example, 0.9), then the currently applicable tariffs of this customer class ought to be adjusted by a factor equal to the inverse of the revenue to cost ratio (in this case $1/0.9 = 1.11$). Similarly, if the revenue to cost ratio was 1.15 (indicating that the class tariffs provide revenues that exceed the cost of serving the class by 15%), the currently applicable tariffs will need to be adjusted by the inverse of 1.15 (i.e., 0.869) so that it would not provide revenues over the cost of serving its customers.
- **Worksheet E1.3:** This worksheet provides a simple volumetric bundled tariff for each customer class. Despite of its simplicity, there are very few examples of such design currently in place.¹²

¹² This design is used for service in Qatar by Kahramaa. Some utilities in the US are seeking—with varying degrees of success—to apply this volumetric rate design on the very large transmission customers away from the traditional two part rates for energy and capacity.



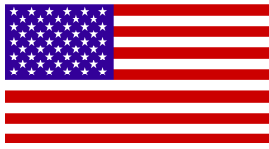
- **Worksheet E1.4:** This worksheet calculates the volumetric but unbundled tariff for each customer class. Under this tariff, each customer will pay a volumetric tariff for the commodity (energy and capacity), for transmission service, and distribution. Under this approach, the customer would receive a bill identifying each component independently.
- **Worksheet E1.5:** This worksheet extends the unbundled volumetric tariffs calculated in Worksheet E3 by further separating the customer charges in the “Distribution” function. Under this tariff design, each customer will pay a fixed customer charge per month (Column 12), in addition to a volumetric per kWh rate for distribution demand, as well as for Transmission and Generation services. This design is the point of embarkation to many other designs in the second module of this study.

Worksheets E2.1 to E2.5 follow exactly the norm explained for Worksheets **E1.1 to E1.5**, but are applicable on the different customer groups classified by voltage level. Accordingly, they provide the R/Cs, the proposed tariffs that would grant IESCO the opportunity to collect the revenue requirements at the current tariff designs, and other preliminary rate structures at the appropriate voltage level.

h. Reference Sheets; Peak Load Data Used in the Model

The reference sheets included with the Model have been primarily used to calculate the Peak Load. Peak demand data based on voltage differential for all consumer categories was derived through load analysis of 668 IESCO feeders after refining the data of 794 feeders. To achieve this objective, IESCO’s daily peak load data of each feeder on the day (May 19, 2011) when the IESCO system experienced maximum load in FY 2010-11. Load data collected according to feeder was used to develop the allocation factor for each customer class for the assignment of demand-related costs of IESCO to each customer class which include:

- Generation Capacity Fixed Charges
- NTDC Transmission Charges (UOSC)
- IESCO’s Sub-Transmission & Distribution Charges (Distribution Margin)



Log sheets of May 19, 2011, where feeder-wise maximum load in Amperes (Amps) is recorded on hourly basis for each day, were collected from all IESCO grid stations. Feeder-wise peak load data was extracted from the log sheets to develop a peak load data sheet organized by feeder, which was translated into grid station level peak demand in terms of kW for each feeder using the following formula:

$$KW = 1.73 \times I \times PF \times V$$

WHERE

kW = Demand on the Feeder at Grid station Level

I = Peak Load Current of the feeder in AMPs

PF = Power Factor (Assumed as 0.95)

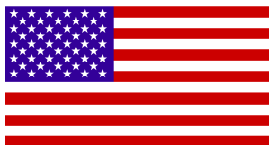
V = Voltage level of the Feeder (132KV/66KV/11KV)

PDP operational audits conducted for all DISCOs having load profiles similar to IESCO were used to benchmark the technical loss at each level of power distribution in IESCO starting from 11KV onwards as follows:

Table:11

	11KV	0.4KV	0.2KV
IESCO	7.97%	5.62%	0.13%
Average (LESCO,FESCO,GEPCO)	5.71%	2.74%	0.24%

Since the results of IESCO were relatively higher than other comparable DISCOs, the average of the technical losses assessed for LESCO, Faisalabad Electric Supply Company (FESCO) and Gujranwala Electric Power Company (GEPCO) were used as a benchmark to estimate demand at customer’s metering point on the peak day of IESCO



for allocation of costs. However, for 132 KV segments of the power transmission and distribution network, technical loss was assumed as 2.5% as approved by NEPRA.

Peak demand by feeder calculated at the grid station level was allocated to each customer class fed from the same feeder. In the absence of demand metering for most of the domestic and small commercial customer classes, feeder-level demand of feeders serving mixed categories was allocated on the basis of average of the sanctioned load and connected load data of all customer classes served from the respective feeder at different voltage levels. To make the allocation basis equitable, sanctioned and connected, load data of customers was adjusted for technical losses to arrive at figures at the grid station level to form the basis of demand allocation.

For example, peak load of the PAF RWP CANTT 11KV Feeder recorded as 220 Amps on May 19, 2011 converted into demand at 0.95 power factor as 3,977kW was allocated to various customer classes served at different voltage levels as shown below:

Table 12: Allocation of Feeder’s Demand of 19th May, 2011

Distribution Voltage	No of Cust.	Load At Meter (MW)		Load at Grid (MW)				Peak Demand (MW) Allocated
		Sanctioned Load	Connected Load	Sanctioned Load	Connected Load	Average	% Share	
0.2kV	3,286	8.041	11.746	8.823	12.889	11	65.9%	2.622
0.4kV	251	3.972	4.430	4.348	4.849	5	27.9%	1.111
11kV	1	0.950	0.950	1.010	1.010	1	6.1%	0.244
Total	3,538	12.963	17.126	14.182	18.749	16	100.0%	3.977

Similar analysis / calculations were made for each distribution feeder of IESCO for allocation of peak demand imposed on the feeder by customer categories served at different voltage levels on the respective distribution feeder. Then, demand allocated to each customer class at the feeder level was summarized to arrive at the grid station level of various customer categories and adjusted for losses to arrive at customer class peak demand at customers’ meters as follows:

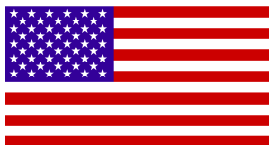


Table 13 – IESCO Grid Station Level Demand (MW) on May 19, 2011

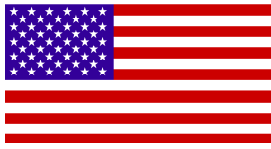
Distribution Voltage	Peak Demand (kW) Allocated at Meter					
	Meter	0.2 kV	0.4 kV	11 kV	132/66 kV	CDPs
 Adjustment for Losses to Arrive at Meter-Level Demand						
0.2kV	922	922	924	952	1,012	1,039
0.4kV	231		231	238	253	260
11kV	140			140	148	152
132/66kV	101				101	104
Total	1,394	922	1,156	1,329	1,515	1,555

IESCO's customer's peak load imposed on its system at various distribution voltages was used to arrive at the percentage share of customers served at each voltage level as follows:

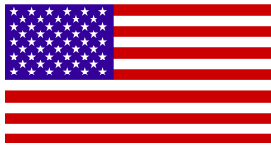
Table: 14 – Share in Demand Related Services Cost

Distribution Voltage	Demand Related Cost Allocation Factors			
	0.2 kV	0.4 kV	11 kV	132/66 kV
0.2kV	100.0%	80.0%	71.6%	66.8%
0.4kV		20.0%	17.9%	16.7%
11kV			10.5%	9.8%
132/66kV				6.7%

Finally, the demand-related cost allocation factors were used to allocate the unbundled functionalized demand related costs to each customer class in accordance with its share in demand at various levels of distribution. For instance, 0.2KV system related costs will be 100% allocated to customers receiving distribution at 0.2KV level whereas they will be allocated 80%, 71.6% and 66.8% of the 0.4KV, 11KV and 132/66KV system-related cost respectively.



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8. Technical Notes

a. Sub-Functionalization of Distribution Assets

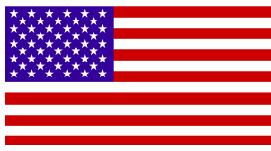
If cost of service and rate design aims at arriving at the cost of serving voltage differentiated customer classes, the distribution RB has to be further sub-functionalized to its subdivisions to recognize that some voltage levels do not utilize specific assets. For example, customers served at the primary distribution level should not be responsible (based on cost causation principle) for the cost of transformers that are necessary to serve the secondary voltage customer.

The two scenarios follow the industry standards in the functionalization of the distribution assets further to its subdivisions of “Primary”, “Transformers”, “Secondary”, “Services Customers”, “Meters”, “Street Lighting”, “Accounting”, and “Sales”. In many cases, the balance sheet data do give a direct one-to-one match for the exact functionalization. Some items that may be dedicated to “Street Lighting” are 100% dedicated to “Transformers”. Similarly, others may be 100% dedicated to “Meters”. On the other hand, assets that benefit all voltage levels (e.g., Intangible Plant, Leasehold and Freehold Land, Buildings and Fixtures, Poles and Towers, etc.) are functionalized as “Primary”. General Plant RB items also benefit all voltage levels, hence the allocation to “Primary”. Underground Conduits and Devices are functionalized to their usual Secondary Voltage Customers, and so on.

Once the different RB items are functionalized to their appropriate subdivisions, the functionalization of Accumulated Depreciation balances follows exactly the same manner. For WC and RB Offsets, they are functionalized according to the functionalization of the entire net rate base. It is noteworthy that there are no RB items functionalized for “Accounting Customers” and “Sales Customers”, as will be discussed further in **Worksheet C1**, these are accounts for operation expenses.

b. Classification of Distribution Plant

The next step to the functionalization of the distribution rate base data to their appropriate subdivision is the classification to Demand- and Customer-related costs. This classification step pertains to costs functionalized as “Primary”, “Transformer”, and “Secondary”. Costs



associated with “Services Customers”, “Meters”, and “Street Lighting” are classified directly as “Customer Only”.

The practices followed in the industry use one of two approaches, the Minimum-Size Method, and The Minimum-Intercept Method. The two approaches are discussed below with emphasis on the former as it is used in the template. A third possible approach is suggested for consideration (the Adjusted-Load Duration Curve) once its data is available.

i. The Minimum-Size Method¹³

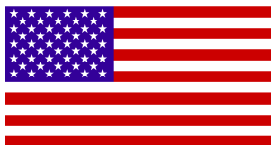
The approach used in the template assumes that there is a minimum distribution system that is dedicated to serving the minimum loading requirements for customers. The method is based on conducting a study to determine the minimum size of different assets (e.g., poles, conductors, cables, transformers). Once this minimum size is determined for each customer class, their total (i.e., the minimum system for each voltage level times the number of customers at that level), is subtracted from the total investments in the different assets to represent the customer portion of the distribution plant. The remaining balances will be classified as demand-related costs. The available cost of service studies that used this approach indicate that approximately 70% of the rate base in “Primary Distribution” is allocated to demand, and 30% to customer, while for “Secondary” (usually including “Transformers”), it is approximately 55% to demand and 45% to customer. **Worksheet B3** (in range M17:T70) allows the user to determine this ratio to reflect the available minimum-size studies in the utility. The ratios in **Worksheet B3** are not currently set on the above benchmarked values (70%-30% for “Primary”, and 55%-45% for “Secondary”) to highlight the flexibility of the Model to accept different values.

ii. The Minimum-Intercept Method.¹⁴

Equivocally reported to be more accurate in representing the customer and demand components of the distribution assets, this method uses regression analysis to estimate a curve that relates installed cost to current carrying capacity or demand rating. Extending the curve to a no-load point (zero intercept on the y axis) would provide the estimated customer portion of the cost. This approach is both data intensive and complex—it is not used in this study.

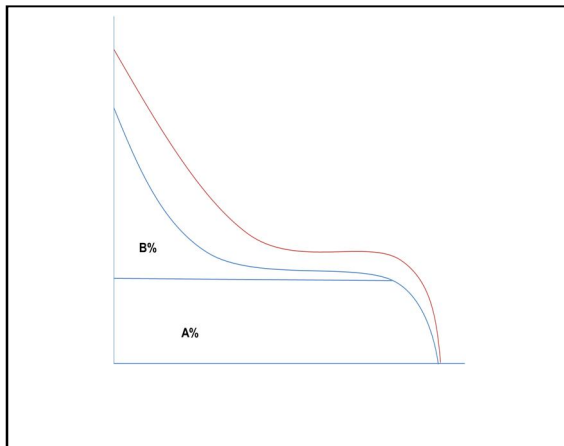
¹³ See NARUC Manual at 90/91.

¹⁴ Id. At 93/94.



iii. The Adjusted Load Duration Curve Approach (Decision 2 Worksheet)

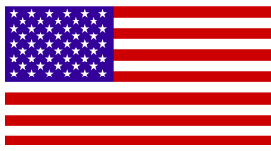
The adjusted load duration curve is constructed from the hourly load data of the utility (the curve in red in the panel below) from which the loads of the customer classes served at the transmission level are subtracted. The remaining load data are exclusive to the distribution system (the load duration curve in blue). The percentage of the area under the curve at a slope close to zero (i.e., parallel to the x axis) represents the size of the minimum system dedicated to serve customers, and the remaining percentage represents demand. Accordingly, A% of the area under the blue curve below will be used to classify the various distribution assets to customer, while B% will be used to classify to demand.



Although this approach is relatively simple, it is not commonly used as a standard method to classify distribution accounts. Further, its use is commonly reserved to the classification of generation assets to demand and energy in information-short systems, and not for distribution. However, the rationale that customers' cost of the distribution assets in relation to the additions needed to meet their

increased demand could be approximated by the relationship between the base consumption and above-base consumption level is relatively acceptable—and a reasonable stop-gap measure till further, and more accurate studies are available.

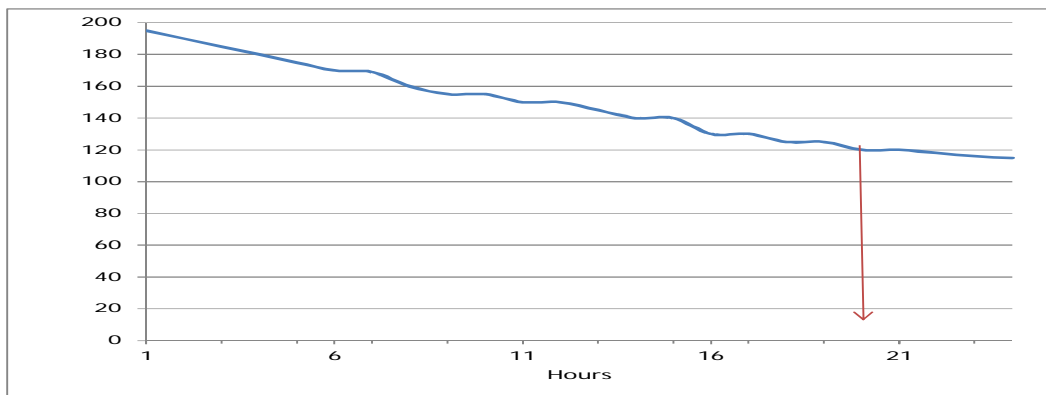
An example for the type of hourly data compiled from a substation at the appropriate voltage level is demonstrated in Table 15. Columns 1 and 2 are the usual load duration curve for the representative substation. Column 3 represents the sorted hourly loads in a descending order, which were used to graph the classical load duration curve for this substation. It is determined visually that the base load for this substation is served at all hours after hour 20. The relative weight of this base load to total load served by this substation in this peak day is classified as customer, and the weight for the remaining hours is classified to demand. Column 4 is the sorted energy at each load level, Column 5 is the relative weight of the sorted energy for each hour to the total energy produced (total is 40,407 MW), and column 6



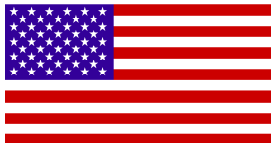
is the cumulative summation of each hour. The cumulative weight of hours 20-24 (column 5) is 32% leaving 68% to demand.

Table 15: Applying Load Duration Curve Data to Classify Distribution Rate Base

Hour (1)	Load (2)	Sorted Load (3)	Sorted Energy (4)	Relative Energy Hourly Weight (5)	Commulative Hourly Weight (6)
1	120	195	195	0.48%	100.00%
2	115	190	380	0.94%	99.52%
3	116	185	555	1.37%	98.58%
4	118	180	720	1.78%	97.20%
5	125	175	875	2.17%	95.42%
6	130	170	1020	2.52%	93.26%
7	140	169	1183	2.93%	90.73%
8	145	160	1280	3.17%	87.80%
9	150	155	1395	3.45%	84.64%
10	155	155	1550	3.84%	81.18%
11	169	150	1650	4.08%	77.35%
12	170	150	1800	4.45%	73.26%
13	180	145	1885	4.67%	68.81%
14	190	140	1960	4.85%	64.14%
15	195	140	2100	5.20%	59.29%
16	185	130	2080	5.15%	54.10%
17	175	130	2210	5.47%	48.95%
18	160	125	2250	5.57%	43.48%
19	155	125	2375	5.88%	37.91%
20	150	120	2400	5.94%	32.03%
21	140	120	2520	6.24%	26.09%
22	130	118	2596	6.42%	19.86%
23	125	116	2668	6.60%	13.43%
24	120	115	2760	6.83%	6.83%
			40,407		



The application of this approach requires the hourly load data from the relevant substation classified by voltage level.



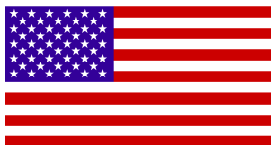
c. Coincident and Non-Coincident Allocation Factors

The two scenarios can use the 1CP or 12 CP of each customer class or voltage level to arrive at their relative share in demand-related costs. These important allocation factors are compiled in Worksheets D1.5 and D2.5. The source of these data are dedicated engineering and field studies that collect data from meters at different voltage levels to arrive at the appropriate share for each class (including accounting including their associated loss levels). In the long run, there is no substitution for conducting these studies and incurring the required investments in the dedicated meters to arrive at the accurate and fair representation of each customer class. In the short run, it is perhaps possible to arrive at an approximation of these allocation factors from data compiled from a limited number of representative circuits in the system that predominantly serve a specific customer class.

The profile of each of the three major customer classes (Residential, General, and Industrial) may be estimated from hourly load data collected from a profiling substation that is as close as possible to serving almost exclusively a single class of customer. The use of these data in tandem with a) total-system data and b) supporting empirical field studies to determine the associated losses for each class can provide reasonable proxies for the use of FACOS. An example of such approach assumes that there are data from three representative substations for each customer class (classes A, B, and C) can provide hourly load data that can be compared to hourly system-wide load data.

Using the example shown in Table 16, system-wide data determined that it has peaked on 1400 hours on July 15. During this very hour, hourly load in representative substations A, B, and C were determined to be 120 MW, 108 MW, and 135 MW, respectively. A comparison between these hourly load to the total megawatt-hour (MWh) of the day for each class will determine: a) the representative substation average demand, and b) the load factor (LF). Average demand is the division of the July 15 MWh use (Column 2) by 24, and LF is the division of this average by use in 1400 hours (from Column 1). Column 4 indicates that the LF for Class A is 0.79, Class B 0.63, and Class C 0.58. In this month (i.e. July), system sales to each customer class were determined as shown in column 5.¹⁵ The average demand for each customer class is easily calculated by dividing the MWh sales by the

¹⁵ These estimates have to be adjusted by an engineering study for losses to arrive at the same voltage level of the representative substation.



monthly hours of 730. Once the average demand is estimated, the class CP could be arrived at using the LF (e.g., dividing 616 MW/0.79, would result in a CP of 778.7 MW). The summation of the different classes and expressing them in percentages would provide 1CP allocation factor required. The repetition of this calculation for 12 months in the year would provide estimates for 12CP.

Table 16: Simple Approach to Estimate 1CP and 12CP from Representative Substation Data

Substation	System Peak Day Substation Data				System Peak Month Data			
	CP	MWh	AD	LF	MWh	AD	CP	1CP
	Actual	Actual	(MW)	Est.	Actual	(MW)	(MW)	Est.
	(MW)	1	2	3	4	5	6	7
A	120	2280	95.0	0.79	450,000	616	778.7	17.7%
B	108	1620	67.5	0.63	690,000	945	1512.3	34.3%
C	135	1890	78.8	0.58	900,000	1233	2113.5	48.0%
Day	15-Jul				15-Jul			
Hour	14:00				14:00			
					Total		4404.5	100.0%

The estimation for the non-coincident peak (NCP) for each customer class follows exactly the same rationale explained above with the exception that data for each representative substation will be compiled for its maximum hour that need not be coincident with the system peak. Following the example in Table 17, Class A has used most MWh on August 10, in which its NCP was 138 MW which if compared to total MWh used in this day would give an average demand and LF of 115 MW and 0.83, respectively. Given that system-wide data indicate that average demand for the whole class (compiled from total sales to the class divided by number of hours) is 863, the NCP for Class A is estimated to be 1035.6 MW. The repetition of this calculation for the other classes would result in their estimates for the NCP that could also be represented in percentages. These estimates, particularly if representative date are refined with loss estimates can provide cost-effective inputs for FACOS.

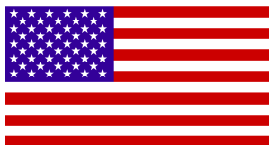


Table 17: Simple Approach to Estimate NCP from Representative Substation Data

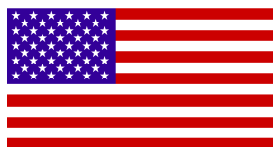
Substation	Class Peak Day Substation Data				System Peak Month Data			
	NCP	MWh	AD	LF	MWh	AD	NCP	NCP
	Actual	Actual	(MW)	Est.	Actual	Est.	(MW)	Est.
	(MW)	Actual	Est.	Est.	Actual	Est.	Est.	Est.
	1	2	3	4	5	6	7	8
A	138	2760	115.0	0.83	630,000	863	1035.6	21.4%
B	112	1792	74.7	0.67	795,000	1089	1633.6	33.8%
c	142	2130	88.8	0.63	990,000	1356	2169.9	44.8%
Day	Varies				Varies			
Hour	Varies				Varies			
							4839.0	100.0%

d. FACOS and the Fuel Charges Adjustment

The FACOS scenarios above unbundle the cost of service to the different customer classes by the generation, transmission and distribution functions. The various results would provide the base period to which the variation in fuel cost could be added through the FCA “Rider” referred as FPA in Pakistan. Riders are additional clauses that temporarily alter or change the terms and conditions of providing electricity service. In addition to the fuel adjustment clause (FAC or FCA), examples in the US and Canada include a wide range of riders dedicated to recover specific costs incurred during the rate period for activities, expenses or assets, which were not part of either the RB or the RR and not included in the conducted FACOS. Examples include riders to recover the costs of procuring energy from renewable (green) resources, costs of serving low income users and riders to recover costs of pilot or experimental programs mandated by the commission. Similar to the different charges within the tariff, the riders must be pre-approved by the commission. The revenues collected from riders will be trueed up periodically to avoid over or under collection. This periodical trueing up process “tracks” the commission’s pre-approved costs (or revenues) collected through the riders, or “trackers”.¹⁶

NEPRA approves a process in which the FAC is referred to as FPA in Pakistan for the various ex-WAPDA distribution companies (including IESCO) is determined and approved

¹⁶ For a good perspective on riders or trackers, see <https://www.aep.com/about/IssuesAndPositions/Financial/Regulatory/AlternativeRegulation/docs/Trackersriders.pdf>.



for application in the upcoming rate period.¹⁷ The process reflects the fuel cost differentials in providing energy (inclusive of transmission losses) to the different utilities between a base period and the upcoming rate period. The change in the rider will be applicable to all consumer categories—except lifeline consumers—and be shown separately in the consumer’s bills on billed kWh basis.¹⁸ As demonstrated in Table 18, different consumer categories will be paying a FAC of PKR 8.0503/kWh rather than what they were paying in the base period of Rs.6.5407/kWh. For the applicable rate period, this is an increase of PKR 1.5096/kWh.

Table 18: Applicable FAC Riders for the month of May 2012

	Rs/kWh
Actual fuel charges component for May 2012	8.0503
Corresponding Reference Fuel Charges Component (Determined)	6.5407
Fuel charges Variation for the month of May 2012	1.5096

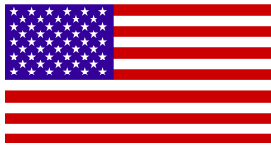
Source: <http://www.nepra.org.pk/Tariff/Ex-WAPDA%20DISCOS/2012/TRF-100%20MFPA%20May-2012%2011-07-2012%206053-70.PDF>.

The process followed by NEPRA above is very similar to the processes followed in many jurisdictions in the US. DISCOs with obligations to serve their customers with generation service—for example as a provider of last resort, or under other regulatory obligations—file periodically with their Commissions to adjust their FAC riders. The filings encompass the detailed information to calculate the fuel cost for the upcoming rate period. These calculations account for the transmission losses, and costs associated with energy from renewables that they are mandated to procure (if any) in addition to any under or over recovery from the previous period. The filings also include the calculation of the rider for each customer class vis-à-vis the currently applicable tariff. In some cases, the filings may include customer impact analysis depicting the total change in customers’ bills as a result in the change in the fuel riders.¹⁹ Following an audit by the Commission, an Opinion and Order is issued to approve the applicable fuel rider.

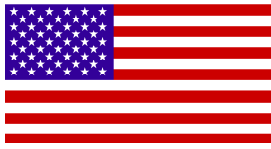
¹⁷ See <http://www.nepra.org.pk/Tariff/Ex-WAPDA%20DISCOS/2012/TRF-100%20MFPA%20May-2012%2011-07-2012%206053-70.PDF>.

¹⁸ Id.

¹⁹ A good example for FAC filing, see <http://dis.puc.state.oh.us/TiffToPdf/A1001001A10I03A95249J46956.pdf>

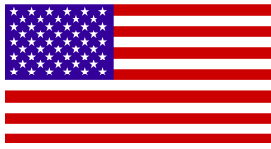


In the context of FACOS, the various designs in **Group E** include in the calculated Generation / Power Purchase cost the base period FAC (e.g. PKR 6.5407). For the new base period, the applicable tariffs suggested in the various designs would only need to add the FAC variation for the new rate period (e.g. PKR 1.5096/kWh). Accordingly, in the new rate period, the different customer classes will pay the generation cost (inclusive of the PKR 6.5407) plus the FAC of PKR 1.5096 per kilowatt-hour (KWh). In the future rate period (for example, starting in January 2013), the FAC process will calculate the fuel charge variation for the period vis-à-vis the base reference fuel charges component (in this case, it is PKR 6.5407/kWh) to arrive at the new fuel charges variations. It follows that if the new fuel charges variations for January 2013 is PKR 2/kWh, the different customer classes will pay the generation costs (inclusive of the PKR 6.5407) plus the FAC of PKR 2/KWh. The reference fuel charge component (i.e. PKR 6.5407 above) will always remain the base period reference against which the change in fuel cost is compared to until the new FACOS is compiled, filed, and approved by NEPRA.



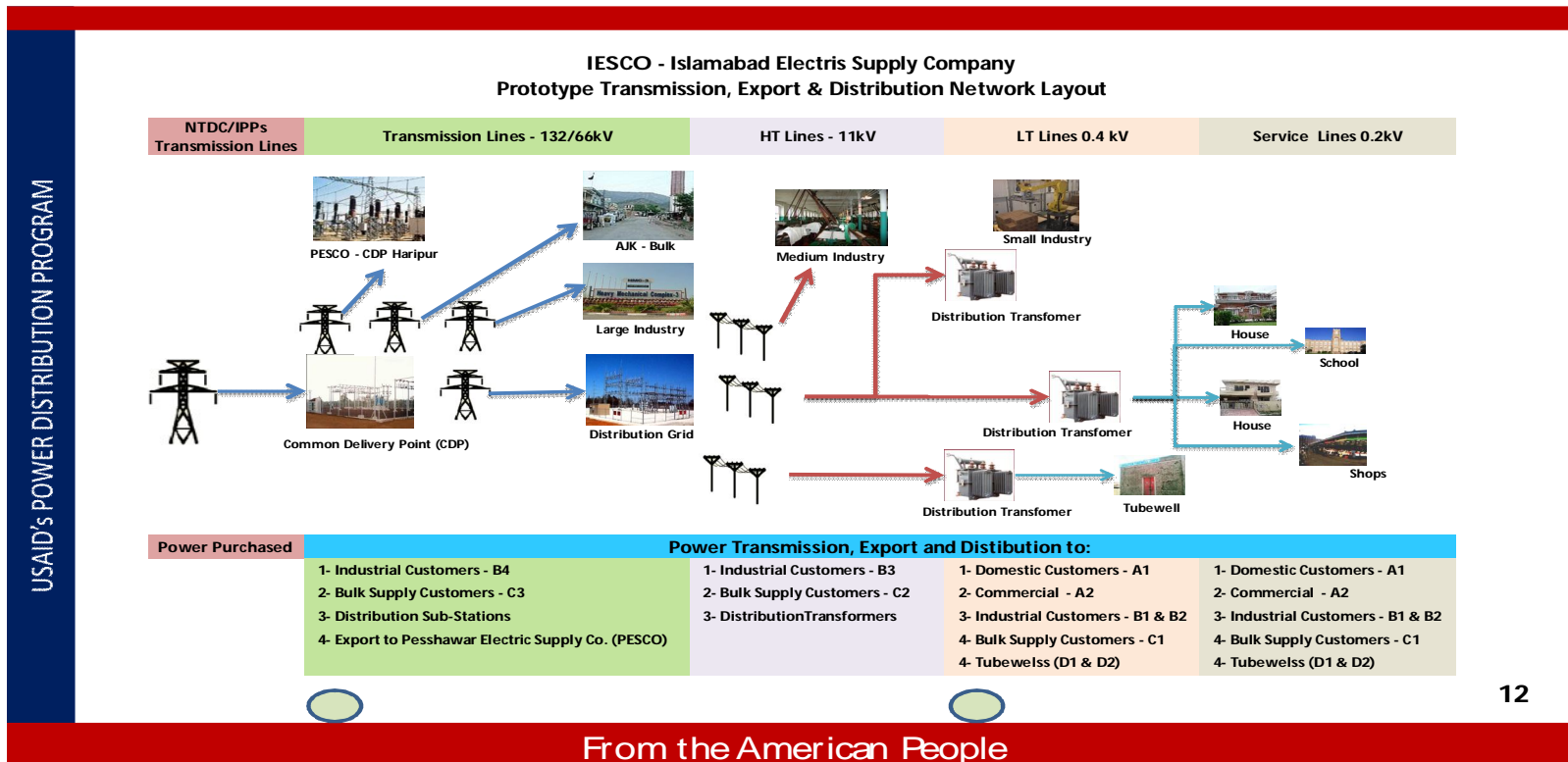
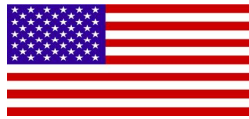
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Appendix 1

Characteristics of the IESCO's Distribution System and the different Customer Groups Classified by Voltage Level



Source: Workshop on Cost of Service & Tariff Design Study, Islamabad, December 20, 2012 Slide