Annex "A"

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GUIDELINES FOR PREPARING ASSET SCHEDULES

for PBR Initial Asset Valuations

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SECTIONS

1. INTRODUCTION

These Guidelines have been prepared to assist privately owned distribution utilities prepare asset schedules that will form the basis for the initial optimised depreciated replacement cost (ODRC) and depreciated historic cost (DHC) asset valuations to be undertaken by regulatory reset experts in accordance with Section 4.8 of the Energy Regulatory Commission's (ERC) Rules for Setting Distribution Wheeling Rates for Privately Owned Distribution Utilities Entering Performance Based Regulation (RDWR)[1]. They draw upon the experience gained in valuing the assets of the utilities entering performance based regulation (PBR) at the first and second entry points.

The asset schedules comprise lists of the assets owned by the utility and used for the provision of services included in the distribution wheeling rate (DWR) determined by the PBR process. These services currently include the provision of regulated distribution services, the provision of distribution connection services and the provision of regulated retail services. In order to prepare the required schedules, the utility's asset base must be disaggregated into individual assets in a manner that is meaningful to both the valuer and the utility. The recommended approach to disaggregating the asset base is discussed in Section 2 of these guidelines.

A valuation asset schedule should include all the information on each individual asset that is required to complete the valuation. This information includes:

- the location of the asset. This is required to assist the valuer determine the accuracy of the asset schedules;
- the date of first installation or commissioning. This is required in order to accurately determine the depreciated historic cost of the asset; and
- the historic cost of the asset. This is required to assist the valuer determine the DHC of the asset base as required by clause 4.8.11 of the RDWR.

Many utilities will find that they do not have adequate records to accurately describe the required attributes for the full asset base. Therefore assumptions must be made in order for the valuation to be completed. Section 3 of these Guidelines discusses the various approaches that can be taken when adequate records are not available.

Current replacement costs need not be included in a valuation asset schedule as these will generally be determined by the valuer. The historic cost of recently installed assets will be a significant input to this determination.

In the second entry point position paper, which describes the rate setting process for utilities entering PBR at the second entry point[2] (Position Paper), the ERC changed the way that it required the asset base to be disaggregated and the asset values to be presented in the valuation report. This disaggregation is not fully compatible with the manner in which the asset base is naturally disaggregated for valuation purposes, and requires individual assets in some valuation asset categories to be reclassified. It further requires the valuer to allocate the value of other assets between different ERC asset categories. These issues are discussed in Section 4.

[1] Energy Regulatory Commission, *Rules for Setting the Distribution Wheeling Rates for Privately Owned Distribution Utilities Entering Performance Based Regulation (Second and Later Entry Points);* Manila, December 13 2006.

[2] Energy Regulatory Commission, *Regulatory Reset for the October 2008 to September 2012 Regulatory Period for Privately Owned Distribution Utilities subject to Performance Based Regulation, Position Paper;* Manila, March 14 2007.

2. DISAGGREGATION OF THE ASSET BASE

2.1 INTRODUCTION

For valuation purposes it is meaningful to classify assets as network or non-network. Network assets form the distribution system that is used to convey electricity between points of injection into the network and individual consumers, while non-network assets comprise all other assets owned by the utility and used to support the functions covered by the RDWR.

Network assets can be further classified as line assets (sometimes called repetitive assets) and station assets. Line assets are used to convey electricity from one point to another and for the purposes of these Guidelines include distribution transformers, service drops and consumer meters. Station assets are the assets found in major substations that transform electricity from transmission or subtransmission voltages to distribution voltages.

In order for the asset schedule to be verified against the assets actually installed in the field, assets listed in the schedule must be described in a way that is useful from a network operations and management perspective. If this is not consistent with the way assets are recorded in the financial asset register, then separate valuation asset schedules, independent of the financial asset register, must be prepared based on engineering asset records. The sections below describe the content of the different asset schedules required.

2.2 LINE ASSET SCHEDULES

2.2.1 Poles

Ideally, each pole on the network should be identified as a separate record in a pole asset schedule. Each record should include the following information.

- Unique identifier. In most cases this will be a pole number. However, the primary requirement is that it is possible to verify by visual inspection, the accuracy of the data on any individual pole listed in the schedule. This requires that it is possible to locate any individual pole in the schedule. Standard practice is to use the same pole number as in the geographic information system (GIS) as this allows the GIS to be used to locate individual poles listed in the schedule. Utilities that do not have a GIS, or do not use unique pole numbers, may need to include a description of the pole location in their asset schedule;

- Pole material (concrete, wood, steel);

- Pole length;

- Date of manufacture or first commissioning; and

- Historic cost[3].

Some utilities have also provided information on the guying arrangements at guyed poles. However, if guy information is not provided the valuer will include an overhead mark-up in the replacement cost assessment to cover the estimated cost of guys.

[3] Although the historic cost is required, the current replacement cost need not be included in the asset schedules as this is generally determined by the valuer.

2.2.2 Pole Top Hardware

Pole top hardware includes the crossarms and insulators that support the overhead conductors. Most utilities have a menu of different hardware arrangements, each identified by a unique standard type number. Each individual standard hardware arrangement should be listed as a separate record in a pole top hardware schedule. Each record, in the schedule, should include the following information.

- Standard type number, which would normally be referenced to a separate schedule or manual of standard hardware arrangements;
- Unique identifier of supporting pole;
- Year of installation; and
- Historic cost (if known).

Utilities may find it convenient to incorporate pole top hardware information in the pole asset schedule, by including additional fields showing the standard type numbers of any pole top hardware installed on a particular pole. In this case separate fields may be required for each voltage level to cater for poles supporting lines at more than one voltage. This approach is acceptable.

The cost of pole top hardware must generally be derived, as utilities usually buy the individual components making up each assembly separately and then assemble the hardware on the pole before the pole is erected. Utilities may derive the cost of each standard assembly by aggregating the procurement costs of all components making up a particular assembly.

In the absence of more accurate data, the year of installation of a pole top hardware assembly is normally assumed to be the same as that of the pole.

2.2.3 Conductors

If sufficient data is available, utilities should provide an overhead conductor schedule that allows each conductor record to be directly verified for accuracy by visual inspection. Such a schedule would contain the following information for each record.

- Unique identifier. This should contain sufficient information to allow the conductor described in the record to be located in the field and is usually described the pole numbers of the two termination poles (hence two fields are required to uniquely identify each entry);
- Conductor type. Three parameters are necessary to uniquely identify an overhead conductor type; conductor material (aluminium, copper, ACSR etc), conductor size and whether the conductor is covered or bare;
- Voltage level;
- Conductor length;
- Number of conductors or phases; and
- Historic cost.

A number of utilities, particularly those using SynerGEE or other network analysis software, have already prepared detailed conductor schedules, where each conductor on the network are uniquely identified by the termination points at either end. These conductor schedules can be used to form the basis for the valuation schedules.

For some utilities the data required to produce the comprehensive asset schedules described above may not be available, or the schedules may take an excessive time to compile. In such case an alternative, albeit less preferred, option is to use the approach described in Section 3.2.2.

2.2.4 Overhead Line Devices

Overhead line devices are miscellaneous devices located on the network to improve network reliability, protect primary equipment or assist network operation. They include:

- disconnectors;
- reclosers and other field mounted circuit breakers;
- voltage regulators;
- Capacitors and Oil Switches;
- Sectionalizing Cutouts;
- Line surge arresters; and
- fault indicators.

A schedule should be provided listing each individual line device. The following information should be provided for each individual asset record.

- Description - indicate device type, whether single or three phase, and any other features that might impact the assessment of replacement cost. For example, if disconnectors are gas insulated or include remote control units this should be stated;
- Rating (voltage, current and fault rating where applicable);
- Location (generally a pole number);
- Quantity (applicable where multiple single phase devices are installed at a single location);
- Year of installation; and
- Historic cost.

2.2.5 Distribution Transformers

The distribution transformer schedule should show each distribution transformer owned by the utility and installed on the network. Each record should include:

- location (usually a pole number);
- transformer rating (in kVA);
- quantity (may be relevant if more than one transformer of similar rating is installed at a single location);
- number of phases (most transformers are single phase but three phase transformers should be identified as such);

- date of installation. If transformers are frequently relocated to optimize the use of available transformer capacity. If a relocated asset was refurbished prior to reinstallation, allowance can be made for an extended life, but this would not necessarily correspond with the new installation date. If no other information is available, installation date has to be used as the best approximation; and

- historic cost.

2.3 CUSTOMER ASSET SCHEDULES

Customer assets include service drops and consumer metering assets owned by the utility. They differ from other line assets in that each individual asset is dedicated to an individual customer. Hence the unique customer identifier rather than a location or pole number is generally used to uniquely identify each individual asset.

Separate customer asset schedules are normally provided for:

- metering transformers;

- meters; and

- service drops.

However two or more of the above schedules may be combined provided all required information is included.

Metering transformers

Each record in the metering transformer schedule should show:

- customer identifier;

- asset description (CT or PT, single or three phase);

- primary voltage;

- quantity;

- year of installation; and

- historic cost.

Meters

Each record in the customer metering schedule should show:

- customer identifier;

- meter description. The meter may be described by manufacturer and type. Alternatively a meter may be described by class and whether it is single or three phase. Sufficient information must be provided to establish the class of the meter, whether it is direct connected or instrument rated and whether the meter is single or three phase;

- date of installation. At the current location, as meters are often changed out and reinstalled in a new location. If a relocated asset was refurbished prior to reinstallation, allowance can be made for an extended life, but this would not necessarily correspond with the new installation date. If no other information is available, installation date has to be used as the best approximation.; and

- historic cost.

Service Drops

In situations where meters are located on the pole the service drop is the cable between the meter and the consumer's main distribution board, provided that this is owned by the utility. Each record in the service drop schedule should show:

- customer identifier;
- cable description. This should include the conductor material and size and whether the cable is single or multi-core;
- service drop length (if known);
- Initial installation date;
- Historic costs.

Many utilities do not measure the actual length of individual service drops but assume a standard service drop length for all customers. In this case, the valuer will estimate the average service drop length during the visual inspection using a statistically sound sampling methodology.

2.4 SUBSTATION ASSET SCHEDULES

Utilities only have a limited number of substations and records on these assets are generally more detailed and complete than for line and customer assets. The date of installation of major primary assets is usually known and accurate records of historic costs are more likely to be available. The ERC requires all assets in major substations to be visually inspected by the valuer.

Utilities should provide the valuer with a single line diagram of each substation together with a schedule of major assets that shows, for each asset:

- equipment ratings (voltage, current and fault rating as applicable);
- date of first commissioning; and
- historic cost (where known).

Civil works and miscellaneous electrical works (such as power and control cabling) associated with a substation can be difficult to schedule or describe. Valuers will generally value these assets as a proportion of the replacement cost of the primary and secondary assets installed at the substation. While this approach may not be particularly accurate, any errors are unlikely to have a material effect on the total asset value. However, civil works and miscellaneous electrical works are substantial in major substations and thus, should be included, whenever data is available.

2.5 NON-NETWORK ASSET SCHEDULES

For asset valuation purposes, non network assets generally include all assets not directly forming part of the primary network or its directly connected protection and control systems. Such assets include land and buildings, office furniture, computer hardware and software, plant, vehicles and tools.

Asset schedules should individually identify all non network assets and show the date the asset was acquired and its procurement cost. The valuation normally involves a full inspection of all assets, although sample inspections may be undertaken for asset categories such as tools, where asset quantities are large and the cost of individual assets relatively small.

2.6 STORES AND SPARES

Stores and spares should be recorded in a separate asset schedule. This schedule should include only assets required to support existing operations and spare levels required to ensure the efficient operations of the business.

Where stocks and spares are held in large quantities, the total quantity of each asset type need only be shown together with an estimated average age. In estimating the average age, utilities may take account of the turnover rate of the asset, as assets with a high turnover would normally be expected to have a lower average age.

The historic procurement cost[4] of all stores and spares should also be shown on the asset schedule. If this is not known from an inventory control system, then it may be estimated by deflating the current procurement cost to reflect the average asset age.

Meters that have been retrieved from the field for testing and recalibration may be included, but only to the extent that these meters are expected to be reinstalled on the network and recorded separately from the brand new inventory. This means that the quantity of meters awaiting testing and recalibration should be reduced by the proportion of such meters that are expected to be rejected for reinstallation. This proportion would normally be estimated on the basis of historical records.

[4] The historic cost of stores and spares will be different from the historic cost of similar installed assets if the latter cost includes installation. See Section 3.4.

3. DATA ACCURACY

3.1 INTRODUCTION

Few utilities will have records that include all the data required to develop full valuation asset schedules, so assumptions and estimates will be required in order to complete the valuation. This is not cause for undue concern, although utilities are expected to put business systems in place to update their asset records on an ongoing basis in order to improve the quality of their asset schedules over time.

For the initial PBR asset valuations, it can be expected that the quality of data available will be better for recently installed assets than for older assets. Furthermore, obtaining accurate data on historic costs and year of first installation is likely to present the most difficulty as this data cannot be established or verified by visual inspection.

Where accurate records are not available, data in the asset schedules will need to be based on assumptions or estimates. These should be based on the best data available and should be the result of robust analysis. Utilities should be able to identify to the valuer the information in the asset schedules that is based on assumptions or estimates. They should also be able to show the basis for any assumptions made and demonstrate the process used to develop estimated data used for valuation purposes.

This section of the Guidelines identifies those areas where accurate data is commonly not available and discusses different approaches that may be used to develop data estimates that could be used for valuation purposes.

3.2 ASSET QUANTITIES

The preferred method for obtaining data where accurate asset quantities are not available is 100% visual inspection. As this is generally required when populating a geographic information system (GIS), utilities that currently do not use a GIS for operational and asset management purposes should consider whether the introduction of a GIS system is appropriate. As most data (except perhaps historic cost) that is generally required for valuation purposes is usually recorded in a GIS database, valuation asset schedules can generally be developed by downloading a report from the GIS database into a Microsoft Access or Microsoft Excel file.

3.2.1 Random Sampling

Where a 100% visual inspection is not practical, a valuation asset schedule may be developed by inspecting a random sample of the asset base using a statistically valid methodology. This should be considered an interim approach only. The ERC will require utilities that base their asset schedules for the initial asset valuation on random sampling to prepare full asset schedules that separately identify individual assets by the end of the second regulatory period.

Where a random sampling approach is used, it is necessary to determine the total number of individual assets in a particular asset category and also the profile of the asset base (or the relative proportions of each different asset type[5]). The total number of assets is usually established from existing engineering or operational records, although the information in these records may need to be supplemented with data gathered from the asset inspections as discussed below. The relative proportion of each different asset type within a major asset category is usually determined by sampling in that the

[5] In these Guidelines, the term “asset category” refers to all assets in the asset base that perform a similar function – for example poles and conductors are asset categories. The term “asset type” refers to all assets with the same specification – for example a 30 foot concrete pole would describe and asset type.

proportions found in the inspected sample of assts is assumed to apply to the whole asset base.

The level of confidence that a random sample of inspected assets accurately represents the total population of a particular asset category depends on the number of assets inspected. When using a sampling approach to develop an asset schedule that is to be relied on for valuation purposes, a minimum sample of 250 assets in each asset category should be inspected, regardless of the size of the total asset population. This will give a level of confidence of approximately 99%.

3.2.2 Conductor

The total circuit length can be assessed from the engineering drawings used for operational purposes, if equivalent electronic data is not available. These are usually overlaid on maps of the distribution area, which allow the length of each line or circuit to be estimated by measuring from scale drawings. Circuit lengths assessed in this way should be disaggregated by voltage level and the conductor for each voltage level should be treated as a separate asset category.

Once the total circuit length at each voltage level has been established (including the average sag factor), this forms the basis for estimating the total length of each type of conductor, taking due account of the fact that the number of conductors in each circuit may vary. If the required information is not available from engineering records, it should be determined by random sampling. The total length of conductor inspected should cover at least 10% of the total circuit length at each voltage level and include a range of different locations randomly selected across the whole network. The inspection process should be designed to produce a profile of the inspected assets at each voltage level in terms of:

- Total length of conductor per kilometre of circuit. This will depend on whether the utility uses a three or four wire distribution system and the relative proportion of single and three phase distribution at the different voltage levels.

- The relative proportion by length of the different conductor sizes used by the utility at each voltage level.

If the random inspections are correctly done the conductor profile for the set of inspected assets should be similar to the overall conductor profile on the network. Hence the inspection findings can be scaled up to derive the total asset quantities for valuation purposes.

Verification of the Asset Schedules

Where conductor asset schedules are derived in this manner the valuer will need to verify the accuracy of the schedules by:

- reviewing the process used to produce the asset schedules from the engineering records. This is a desk top exercise designed to ensure that the schedules accurately represent the available engineering data;

- verifying the accuracy of the engineering records by field sampling and checking the inspected data against the records; and

- verifying the conductor profile at each voltage level by conducting a field inspection using a similar process to that used to develop the initial profile. It is likely that this process would use a smaller sample of assets initially but the number of asset samples would be increased if the profile determined from the initial sampling exercise was materially different from that reported by the utility.

3.2.3 Poles

If the total number of poles and individual pole locations are known then only the relative proportions of different pole types needs to be established. This can be determined using a sampling process that involves a visual inspection of at least 250 poles identified from the engineering records to determine that each identified pole actually exists in the field (and hence that the total number of poles as established from the records is accurate) and also to establish the pole length and type. Provided the poles inspected have been randomly selected the profile of the set of inspected poles can be assumed to apply across the whole network. The number of poles of each type can therefore be scaled up to match the number of poles on the network (after adjustment for any inaccuracies found in the number of poles as shown in the engineering records).

A refinement to this approach would be to treat subtransmission, distribution and secondary system poles as separate asset classes and to separately sample the poles at each voltage level. The cost of a pole is very sensitive to its length and treating poles at each voltage level as a separate asset class would help ensure the valuation took due account of the longest and shortest poles on the network[6]. With this approach it may be feasible to inspect all subtransmission poles and only to use sampling for the poles on the distribution and secondary networks.

If the total number of poles and individual pole locations are not known, the sampling process needs to be extended to establish the average span length at each voltage level and this data can be used to estimate the total number of poles on the network. This sampling is probably best done in conjunction with the conductor sampling discussed in Section 3.2.3 above. If this approach is used care must be taken to ensure that poles supporting circuits at more than one voltage level and poles supporting two or more circuits at the same voltage level are not double counted.

3.2.4 Pole Top Hardware

If no engineering records of pole top hardware are available, then the relative number of different hardware arrangements on the network needs to be established by visual inspection of a sample of assets. This is best done by noting the standard type number of each hardware arrangement installed on a pole in conjunction with the pole inspections described in Sections 3.2.3 above. The total number of each standard pole top hardware arrangement can then be estimated by scaling.

3.2.5 Overhead Line Devices

Most overhead line devices are installed to facilitate the operation of the network, and their locations should therefore be shown on operational records. Asset schedules could be developed from these records.

An exception to this may be surge arrestors and drop out fuses associated with distribution transformers, which may not be specifically shown on engineering records. In these cases asset quantities may need to be estimated on the basis of the number of transformers installed on the network. If this approach is used, the utility will need to be satisfied that the number of devices shown in the asset schedule accurately reflects the number installed in the field. For example, if a utility's current standard is to have a surge arrestor protecting each phase of a single phase transformer then the number of surge arrestors would only equal the number of transformers if all distribution substations are actually constructed according to the standard. A valuer is likely to check this during the visual inspection.

[6] Generally the very long poles will be installed on the subtransmission system and the very short poles on the secondary network.

3.2.6 Distribution Transformers

The number of distribution transformers installed on a network is much smaller than the number of poles or total length of conductors and most utilities will have good records of the location and capacity of all transformers on a network. Transformer nameplates generally include the year of manufacture.

These engineering records should be used to prepare the list of individual transformers that will comprise the valuation asset schedule. Once the list is completed it should be checked for accuracy by visually inspecting a sample of transformers and comparing the actual rating with the rating shown on the schedule. Inaccuracies can arise when engineering records are not updated after a transformer is changed out for a unit of a different rating. If significant inaccuracies are found it may be necessary to inspect all transformers on a network to ensure that the asset schedule is accurate.

Additional information should be provided related to distribution transformers specifying whether the asset are new or reconditioned when installed, the yearly percentage of reconditioned distribution transformers within the registers and its policy on purchasing reconditioned distribution transformers.

For purposes of calculating an accurate replacement cost for distribution transformers, the actual replacement cost for reconditioned distribution transformers per type as well as the percentage of the new asset replacement cost for reconditioned distribution transformers should also be provided.

3.2.7 Customer Assets

The quantity of customer assets depends on the number and type of different customers. Utilities generally have good customer records for billing purposes and these records enable the total quantity and type of customer metering assets to be reliably determined. Asset inspections may be needed as a basis for estimating the total length of each type of service drop cable.

Meters and Metering Transformers

It is not essential to separately list similar meters of different manufacturer or type, if these would have the same current replacement cost. Meter types used for the second entry point asset valuations were:

- single phase direct connected, class 100;
- single phase direct connected, class 200;
- three phase direct connected;
- single phase, instrument rated; and
- three phase, instrument rated.

Additional information should be provided related to meters specifying whether the asset are new or reconditioned when installed, the yearly percentage of reconditioned meters within the registers and its policy on purchasing reconditioned meters.

For purposes of calculating an accurate replacement cost for meters, the actual replacement cost for reconditioned meters per type as well as the percentage of the new asset replacement cost for reconditioned meters should also be provided.

While it is important to record the number of instrument transformers installed at a particular location, it is not necessary to disaggregate current transformers by winding ratio, as this does not have a material effect on the current replacement cost of the transformers. The primary voltage of all metering instrument transformers should be recorded as this will materially affect the replacement cost.

Service Drops

The service drop is the conductor that connects a customer's installation to the network, irrespective of the location of the meter, and should be included in the asset schedule if it is owned by the utility. Some utilities do not record the type and length of service drop cable used to supply a particular customer. Many utilities record the type of service drop cable installed at a particular customer connection point but assume that all service drops have the same standard length. The assumption of a standard length is not sufficiently accurate for PBR asset valuations.

If accurate data on the type and length of individual service drops is not known, this information will need to be determined by visual inspection of a sample of service drops. Generally this will involve inspecting a sample of at least 250 customer installations, measuring the length of service drop cable and establishing the type of conductor used.

- The average length of service drops on the network can be assumed to be the same as the average length of inspected service drops; and

- The profile of different conductor types over the total network can be assumed to be the same as the profile of the inspected asset sample. As the total number of customers is known, the total length of each type of conductor can be determined based on the average service drop length of the inspected sample.

3.3 ASSET AGE

Where assets are individually listed in an asset schedule the year in which each asset was installed or commissioned should also be recorded. However in a large number of cases the actual installation or commissioning year of an asset may not be known and will have to be estimated or inferred. The average age should be applied only to the particular assets in a group which installation or commissioning date is not available and not to the entire group.

As each situation is unique, it is not appropriate to set hard and fast rules as to how asset ages should be estimated. However, the following guidelines are provided to assist the determination of the age of individual assets.

- The age of some assets is recorded on the asset. In particular distribution transformers generally have the year of manufacture on the nameplate and some concrete and steel poles may have the date of manufacture stamped on them.

- The age of many assets may often be inferred from engineering and management records. For example the date of construction of different distribution lines can be inferred from the earliest date of connection of customers supplied from the line. This information may be available from customer records. Alternatively the information may be inferred from the manufacturing date of the older distribution transformers installed on the line.

- Corporate memory may assist a utility to estimate the age of some assets. Long serving or former staff may be able to recall when a particular asset was installed. While reliance on corporate memory may not be accurate, it is sometimes the most accurate method available to determine an asset's age.

- When the initial installation date of a group of assets, such as a length of line, is known or can be reliably estimated, all individual assets making up the group should be assumed to have been installed new at this time unless contrary evidence exists. On this basis pole top hardware, for example, would normally be assumed to have the same age as the pole on which it was installed and surge arrestors and drop out fuses at a distribution substation would be assumed to have the same age as the distribution transformer.

- The age of customer assets, including service drops, meters and metering transformers would normally be based on the date a particular installation was first connected to the network if no information supporting a different age is available.

If it is not possible to estimate the age of individual assets in a particular asset category, or of some of the assets in that category, then an average age will need to be estimated and assigned these assets. Sometimes the average age can be estimated on the basis of purchase records. If a utility knows the number of assets purchased each year, this information can be used to build up an age profile of the asset base, which can in turn be used to determine the average age.

Often such records are only available for recent years and no information is available on the age profile of assets that were purchased before the earliest date for which records are available. In this case the number of assets for which no age records are available can be estimated by subtracting the number of assets covered by the purchase records from the total number of installed assets. The age of the oldest asset still in service then needs to be estimated. In the absence of other information this can be assumed to be the standard life for the asset type. Using this information an age profile of the assets that predate the service records can be estimated. This will generally be a straight line but in some circumstances this assumption can be modified to account for other known information. For example, if it was known that a 1990 typhoon triggered a significant network reconstruction, then it is reasonable to assume that a higher proportion of assets are, for example, 16-18 years old and to reflect this in the assumed age profile.

By combining the age profile derived from the purchase records for newer assets and the assumed age profile for older assets, an overall age profile for all assets of the particular asset type can be estimated, which can in turn be used to derive the average age of all assets of the asset type.

In using purchase records to establish an age profile, it is generally only necessary to go back to the earliest date for which usable electronic records are available. It is not required that utilities embark on a time consuming analysis requiring a detailed examination of archived paper records.

In situations where asset schedules do not list assets individually but provide only the total quantities of different type of assets, an average age for each asset type is all that can be shown. This will need to be derived using a methodology similar to that described above.

3.4 HISTORIC COST

Determining the accurate historic cost of individual assets is difficult for many utilities. While a utility will have a written down historic cost of the asset base in its balance sheet, this is derived from the financial accounts and does not necessarily correspond to an aggregation of the historic costs of the individual assets as recorded in the valuation asset schedule. Furthermore it is not usually possible to accurately reconcile the balance sheet value with an ODRC valuation produced from engineering rather than financial records. If this is the case, there is no basis on which a valuer can give an opinion as to the accuracy of the written down value of the asset base shown in the financial accounts[7].

[7] A major problem for the valuer is an inability to determine whether the asset base represented by the written down historic cost in the balance sheet is accurate. It can be difficult to establish this in situations where assets in the financial asset register (FAR) are not specifically identifiable in the field. Inconsistencies between the asset base represented by the FAR and that used as the basis for the replacement cost valuation can arise due to a number of factors. For example, the balance sheet value will be overstated if an adjustment is not made to remove the undepreciated value of an asset from the register every time an asset is prematurely removed from service. Errors can also arise if a utility's cost allocation policy is not consistent with financial accounting principles. For example, the

A further issue is exactly what costs should be included in the reported historic cost of an asset. All utilities include the procurement cost of the major equipment items as a component of historic costs. However practices differ on the treatment of minor procurement costs such as the procurement costs of the conductor and rods used to ground distribution transformers at the time of first installation, as well as the treatment of the costs of in-house or contracted labor used to install a new capital asset, as well as costs associated with the use of plant and vehicles for the installation. The RDWR requires that such costs be included in the replacement cost.

The historic cost reported for PBR valuation purposes should be consistent with a utility's historic cost allocation policies, provided these are consistent with general accounting standards. Hence, if it is normal practice for a utility to treat equipment procurement costs as capex and installation costs as opex this practice should be followed in determining the PBR historic cost valuation. However, if the utility normally capitalizes initial installation costs, then this practice should be followed for the PBR historic cost valuation. However, in neither case should routine maintenance costs, including the procurement cost of spare parts used for maintenance purposes, be included in the reported PBR historic cost value[8]. The cost allocation policy used for the derivation of historic costs will need to be disclosed to the valuer, who will need the information to assess the reasonableness of the costs reported by the utility. The valuer will also need to disclose the cost allocation policy in the valuation report.

Historic costs may be taken directly from the financial asset register where it is possible to allocate these costs directly to assets as recorded on the asset schedules. It may be possible to allocate costs to some assets in the schedule in this way and then to assume an historic cost for assets that cannot be specifically identified in the financial asset register. This approach is acceptable where the assumed historic costs are based on the known historic costs of assets of a similar type and age.

Where historic costs cannot be taken from the financial asset register, they will need to be assumed. Utilities will be able to derive the current cost of a particular asset type on the basis of its present cost structure and its standard cost allocation policy. The historic cost of assets installed in earlier years may be estimated by deflating the current costs by an appropriate cost index. The Philippines consumer price index is normally used.

Some utilities may have accurate historic costs for assets installed in recent years but not for assets installed earlier. In this case the accurate historic costs should be used where known and costs should be estimated by deflation only for those assets where an accurate cost is not available.

Where an asset schedule shows only the asset quantity and average age for a particular asset type it will be necessary to base the reported total historic cost for the asset type based on the estimated historic cost of installing the asset in the year represented by the average age. This can be estimated by deflating the current cost.

balance sheet value would also be overstated if the cost of spare parts installed during routine maintenance activities are capitalized (treated as capex) rather than expensed (treated as opex).

8 In this context maintenance should be distinguished from refurbishment. Accounting standards define maintenance as expenditure intended to ensure that an asset can remain in service for its expected economic life. On the other hand refurbishment is expenditure intended to enhance expected economic service potential of an asset, either by increasing its capacity or by extending its life beyond the expected economic life for the particular asset class.

4. CLASSIFICATION OF ASSETS

4.1 INTRODUCTION

In order to rationalise the preparation of asset schedules, these Guidelines have classified assets in accordance with the nature of the asset and the manner in which it is expected to be valued. In the Group B Position Paper, the ERC reclassified individual assets according to function, to facilitate the implementation of the Distribution System Open Access Regulations (DSOAR) and the introduction of retail competition.

This means that assets in a particular valuation asset schedule may need to be allocated across different asset functions. This may involve the allocation of individual assets to different functions, while in cases where this is not possible (either because assets are shared or assets are not individually recorded in an asset schedule) the total asset value for a particular valuation category will need to be allocated across different functions.

This section of the Guidelines provides further information on how assets should be allocated to the different ERC functions.

4.2 REGULATED DISTRIBUTION SERVICES ASSETS

Regulated distribution services include the operation of a shared electricity distribution network in accordance with the provisions of the utility's franchise agreement, but do not include the provision of connection services that are potentially competitive under DSOAR or the provision of retail services that may become competitive when retail competition commences. Hence retail distribution services assets include the shared distribution network (excluding assets specifically used to connect an individual customer to the network) as well as assets used to support the management and operation of this network.

The schedule below provides further guidance and is intended in part to increase the uniformity of treatment by different utilities.

Network Assets	
Land and Land Rights	Substation land and other land used exclusively for the management of the distribution network should be included in this category. The replacement cost of workshops and offices that are shared between the different functions will be allocated between each function by the valuer.
Structures and Improvements	Structures and improvements include buildings as well as general improvements to land such as fencing and drainage. The replacement cost of foundations and other civil works directly associated with assets in other categories should be included with their respective assets.
Station Equipment	All equipment in substransmission substations and substations at major points of injection into the network should be categorized as station equipment. Hence separate asset schedules are normally prepared for all substation equipment.
• Power Transformers	
• Switchgear	
• Protective Equipment	

• Metering and Control Equipment	SCADA master stations and centralized network control equipment would be included in this category.
• Communications Equipment	
• Other Station Equipment	
Poles Towers and Fixtures	Does not include poles that only support service drops as such poles are distribution services connection assets.
Overhead Conductors and Devices	Does not include service drops, which are distribution services connection assets.
Underground Conduits	
Underground Conductors and Devices	
Line Transformers	Line transformers owned by the utility but used to supply customers metered at distribution voltage should be considered distribution services connection assets (since the provision of such an asset is potentially competitive). However transformers that supply a single customer should be considered a regulated distribution service asset if the customer connection point is on the low voltage side of the transformer, unless, otherwise defined under the DSOAR.
Power Conditioning Equipment	This category refers to equipment such as capacitor banks for power factor correction, voltage regulators, generators used for spinning reserve or voltage stability, VAR compensators etc.
Meters, Metering Instruments and Metering Transformers	This category should not include customer meters or meters installed within a substation, as these are substation assets. However metering equipment at the connection point of a utility owned subtransmission line to a TransCo line of the same voltage should be included in this category.
Information Technology Equipment	
Regulated Entity Property on Consumers' Premises	This category should not include line assets and distribution substations that formed part of the shared network and that are located on private land or (in the case of distribution substations) in a building supplied by a customer.
Street Lights and Signal Systems	
Submarine Cables	
General Plant (Non-Network Assets)	Assets that are used exclusively for the provision of regulated distribution services should be included in the relevant category. The replacement cost of assets that are shared with other functions, or where the use cannot be specifically determined, will be allocated across the three functions by the valuer.
Land and Land Rights	
Office Furniture and Equipment	
Transportation Equipment	
Tools, Shop and Garage Equipment	
Laboratory Equipment	

Information Systems and Equipment	This would include (but not be limited to) geographic information systems and associated hardware, provided that this equipment was not directly connected to the network. It would also include network analysis software.
Power Operated Equipment	
Miscellaneous Equipment	
Materials and Supplies	
Transferred Subtransmission Assets	This category should include only those subtransmission assets purchased from TransCo in accordance with Section 9 of the Electric Power Industry Reform Act 2001 (EPIRA). Other subtransmission assets should be included in the relevant network category.

4.3 DISTRIBUTION CONNECTION SERVICES ASSETS

Distribution connection services involve the connection of individual customers to the network and are considered potentially contestable under DSOAR. Hence distribution services connection assets are assets (excluding metering assets) that are owned by the utility but located downstream of the point at which the customer installation is connected to the shared distribution network, as well as assets used by the utility to support and manage the provision of distribution connection services. Many of these supporting assets will be shared by other network functions and their replacement cost will therefore need to be allocated between the different function by the valuer.

4.4 REGULATED RETAIL SERVICES ASSETS

Regulated retail services assets are assets required to support the supply of electricity to those customers in a utility's franchise area that have not been deemed contestable by the ERC in accordance with Section 31 of EPIRA. Currently no utility customers have been declared contestable so all non-network assets used to support the supply of electricity to customers should be included in this category. However many such assets will be shared with other functions and the replacement cost of these assets will need to be allocated across the different functions by the valuer.

Metering of the quantity of electricity supplied to individual customers is considered a retail service so all customer metering assets should be included in this category.