TIME-BASED AND LOCATIONAL DISTRIBUTION USE OF SYSTEM TARIFFS WITH SELECTIVE CONSIDERATION OF NETWORK COMPONENTS

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ABSTRACT
An efficient tariff structure is such that it induces clients to use the network at times and places of least cost, thus reducing network investment requirements and stimulating the use of least cost energy alternatives. The Distribution Use of System Costs (DUoSC) are driven by two factors: the customer’s contribution to maximum demand, and the location of his connection to the grid. Therefore, cost reflective tariffs need to vary according to daily and seasonal time of use, depending on the situation of network load and also have some differentiation between regions with diverging network costs and load behaviour. This way, customers can be incentivized to use the network more efficiently, at better times, and potential distributed generation can be directed towards load centres. This work proposes a novel methodology integrating the concepts of time-based and locational costs in order to enhance the knowledge of DUoSC and enable tariff setting in the presence of DG.

INTRODUCTION
The main objective of a tariff model is to allocate society’s resources efficiently. Primarily, rates have to reflect marginal use of system costs so that customers will choose the cheapest energetic (production plus transportation). Also, they must give sufficient incentive towards best shared use of the grid, thus reducing energy supply costs, while competing in its best performance with alternative energetics [1][3][9].

An effective tariff structure, therefore, induces clients to purchase at the times (annual view) and places with smallest network cost, this way reducing system expansion costs and stimulating the use of the energy alternative with least cost for society.

Distribution Use of System Costs DUoSC are driven by two fundamental factors: (1) the customer’s contribution to maximum network demand, responsible for its expansion, and (2) the location of his connection to the grid [1].

Furthermore, costs vary according to the type of network deployed and service quality (which are strongly related).

The methodology currently in use in Brazil already seeks to evaluate hourly DUoSC for network ranges (bundles of voltage ranges), although the application of cost reflective tariffs with suitable economic signals is being deterred by a certain stiffness of regulation.

Locational tariffs approach the second driver, evaluating UoSC according to the (electrical) distance between loads and generation through load flow simulation.

Thus, in principle, tariffs should differentiate periods of use according to network load, allowing customers to adopt an efficient usage of the system within, each day and throughout the year, as well as distinguish between regions with different load behaviour (different times of peak load), taking into account the customers location within the grid.

Specifically, the location of new generation sites within the distribution system determinates the benefits these new customers can bring to grid optimization. Therefore, it’s necessary that potential distributed generation can be directed towards locations where they are more beneficial, through adequate tariff signals.

Although the methodology of DUoSC calculation used in Brazil takes hourly variations into account, basic objectives of network tariff design aren’t being achieved because of the great regional differences in load behaviour and network cost levels that vary strongly throughout the country due to the huge distances between load and generation centres [8].

Also, the computation of network charges for generators connected to voltages lower than 69 kV continues to be an unsolved problem in Brazilian regulation, since these tariffs don’t hold any relation to the costs imposed by these customers on the grid, a problem exacerbated by the recent growth of distributed generation.

The stiffness of regulation regarding tariff structure that doesn’t allow locational or zonal/regional tariffs on distribution level has obstructed effective optimization of network use. Worse even, it has induced customers to reduce their demand in periods that don’t correspond to network peaks, thus wasting clients’ efforts to reduce demand at times that won’t bring any reduction of network investments.

For these reasons, a new step towards the calculation of DUoSC with a time-based and locational perspective needs to be prepared. This is currently feasible in Brazil, since the networks of all distribution service operators are completely geo-referenced.

Calculating nodal costs not necessarily implies the application of nodal tariffs [9], but it creates the possibility of obtaining regional or sub-regional tariffs, with varying levels and signals, allocating economic resources and surplus optimally, and it increases the electricity sector’s knowledge about the service it provides: electric energy transportation. The tariffs obtained in this way for each
category of customers will be more precise and cost-reflective than current rates, consequently improving the economic signal given to customers.

In a certain way, distribution tariffs are already regionalized in Brazil, since each Distribution System Operator – DSO – has its own costs that reflect the peculiarities of each service area. Within each service area, however, there are also networks with distinct characteristics and load behaviour, as well as several types of customers with different transportation costs. Hence, it is plausible to distinguish these areas within each service area in order to allocate economic resources and surplus more efficiently.

This regionalization would reduce cross subsidies between system users or, at least, add transparency to their existence (more in depth discussion in [5]). The challenge is to find a point that balances out the benefits of regionalized pricing against the costs entailed by this regionalization, as well as customer understanding and acceptance [9].

**LOCATIONAL USE OF SYSTEM COSTS**

Locational UoSC are currently used in Brazil to obtain transmission use of system tariffs. The formulation employed is that of Investment Cost Related Pricing – ICRP:

\[ \pi_j = \sum_i \frac{C_i}{\text{Cap}_i} \times \beta_{i,j} \]

\( \pi_j \) = UoSC of demanding or injecting 1 kW at bus \( j \);

\( C_i \) = Annual cost of element \( i \), in S/year;

\( \text{Cap}_i \) = Capacity, in kW, of element \( i \);

\( \beta_{i,j} \) = flow through element \( i \) when 1 kW is injected or demanded at bus \( j \).

The fundamental question in this model is calculating \( \beta_{i,j} \), which is done by load flow simulation, considering a certain configuration of the grid, with predetermined generation dispatch and loads reflecting the situation of the network at the time of peak demand.

Even though ICRP uses data of present network configuration in its load flow simulations, it is a proxy to Long Run Marginal Costs – LRMC. The assumptions made are that the network is operating at optimum level, that it can vary its capacity continuously and that increases and reductions of flow in each element of the network imply in a proportional variation of capacity and of costs. In reality, it is a Medium Long Run Cost proxy to LRMC, since the present network configuration is used.

The marginal analysis here is to ask what the variation of load flow, and consequently of capacity and costs is when one demands or injects an extra 1 kW at a certain bus of the network.

In order to obtain LRMCs, the unit costs of each element have to be computed as the relation between an element’s annualized cost and its capacity, in kW, instead of the flow that transits through the element. This way, distinct load levels in each element aren’t taken into account, which would lead to a misguided tariff signal, since the average cost of each element, in $/kW, would be contrary to common sense: high when the element has low charge and low where elements are stressed. Using capacity is the same as considering that all elements have the same level of charge.

There are some other considerations to be made on the results of this model:

1. The closer from generation a load is, the smaller will be its cost, since less network elements will be in use, and vice-versa;
2. A load or a generator connected to a certain bus \( j \) have the same cost in absolute value, with inverted sign. When the cost of a load at a bus \( j \) is positive, it means that it is adding to network costs, in which case a generator connected to this same bus would relieve the network providing an avoided (negative) cost of same absolute value;
3. When a load is demanded at bus \( j \), there will be an increase in flow in some elements (increase in LRMC) and a reduction in other elements (reduction of LRMC). The total nodal cost will depend on the quantity of elements with increased or reduced flow and their costs.
4. Because unit costs are calculated with the elements’ capacities, the sum of all nodal costs multiplied by the respective loads or generation won’t recover total annual costs of all elements [10]. Thus, it is necessary to make an adjustment to recover these costs, and there are several ways to do this that will not be discussed in this article.

A deficiency of this methodology is that it considers that with the power dispatch determined in calculations all network elements are at their peak load at the same time, but this doesn’t happen. Even at the moment of overall system peak, there are elements that are not at their individual peak [2][3]. For instance, the system may reach its peak demand at 19h and dispatch was determined for this time of day. Probably, most of network elements will reach their individual maximum demand at this same time, but not all of them. There can be elements with peak demand at 10h, 16h, etc.

Another point is that clients have distinct load behaviour and contribute differently to the formation of the networks peak loads.

**HOURLY USE OF SYSTEM COSTS**

The DUoSC methodology currently in use in Brazil relies on the same marginal analysis [8]. The question posed is what the variation in flow (and consequently of cost) is, when a load of 1 kW is requested at a certain point of the network.

However, the network configuration is very much simplified, having the following system segments as great bundled "equivalent buses":

i. A2 Network (88 kV - 138 kV) – High Voltage;
ii. A3 Network (69 kV) – High Voltage;
iii. MT Network (2,3 kV - 44 kV) – Medium Voltage;
iv. BT Network (< 2,3 kV) – Low Voltage;

That is, from a “locational” point of view, the methodology considers very few system “busses” or “nodes”. On the other hand, this methodology is quite precise in evaluating the time of the network’s peak loads and is, therefore, very effective in optimizing system use,
brings benefits with the postponing of network investment.

It is founded on the concept that network costs are related to their peak demand, and that it is the increment in maximum demand of networks that entails network investment and expansion.

It is possible to verify each network’s peak load and, taking into account the contribution of each custom, DUoSC can be computed for each hour and later grouped into time periods.

The calculation of DUoSC consists in determining what the increases of flow are on all networks involved in serving a specific type of client from its connection point up to the 138 kV network. The costs associated with each customer for use of networks with maximum demand at each hour h are obtained adding up the product of these flow increases in each network with their respective costs.

NUSC at hour h of a specific client type

\[ \text{NUSC at hour } h = \sum \text{Flow increase of networks with peak demand at hour } h \times \text{Expansion cost of networks with peak demand at hour } h \]

After calculating DUoSC for each hour h, time periods with distinct costs are established for tariff setting. Alternatively, these time periods can be established a priori based on a detailed analysis of the annual load behaviour of networks.

Furthermore, the methodology has to contemplate the relation between the monthly (billed) maximum demand and the annual increase in flow on the networks, with which network expansion costs are calculated:

1. Firstly, the flow increment in each network when an extra 1 kW is demanded at a specific time and network segment has to be considered. Not necessarily there will be an additional flow of 1 kW in all higher voltage levels, because the system isn’t completely radial, specially at higher voltages, and also because of the presence of distributed generation. As such, all costs from the connection point of the customer up to the highest voltage segment (A2 – 88kV to 138 kV) are aggregated taking into account the proportion of flow through the system. This additional flow is obtained based on a single line diagram of the network.

2. One must also keep in mind that the customer’s monthly maximum demand not necessarily occurs at the same time as the networks peak demands, that are responsible for cost increments. The cost a customer imposes isn’t a function of his individual maximum demand, but of his contribution to network peak demand [3][4]. This way, when 1 kW of monthly maximum demand is billed, there isn’t necessarily an increase of 1 kW to the annual maximum demand of networks. There usually are several distinct network load shapes (or types) and each customer contributes differently to the maximum demand of each network type, according to his own load behaviour.

3. Each segment of the network system has elements with distinct behaviours and times of maximum demand, due to the sum of the distinct behaviours of all clients they serve. The more similar the load shape of a customer and a network are, the greater the probability of use. This way, the probability of each type of customer being connected to each type of network is taken in to account. A more detailed formulation can be consulted in [6].

4. Lastly, cumulative power losses over the distribution system have to be taken into consideration. Due to technical losses there is a difference between the maximum demand measured at the customer’s connection point and the power that is transported upwards through the system [11].

As such, the DUoSC allocated to each client j, in each hour of maximum demand of each segment of the network or bundle of segments k involved in serving this client is computed as follows:

\[ DU\text{oSC}_{j,k} = CME \times \theta^{(k0,k)} \times (1 + fpp^{(k0,k)}_{j,k}) \times \pi_{k,j} \times P_{j,h} \]

Where:

- \( CME \) is Marginal expansion cost or LRMC of segment k.
- \( \theta^{(k0,k)} \) is load flow through each system segment k when 1 kW is requested at element k0 to which the client is connected.
- \( fpp^{(k0,k)}_{j,k} \) is probability a client of type j is connected to a network from segment k with peak demand at hour h. as obtained in [6];
- \( \pi_{k,j} \) is coincident factor; demand of a client of type j at hour h divided by his maximum demand;
- \( P_{j,h} \) is load flow proportion due to each client type

If daily tariff periods are defined in advance, the formulation can be adapted as follows:

\[ DU\text{oSC}_{j,u} = \sum_{k=0}^{A^2} DU\text{oSC}_{j,k} \]

\( DU\text{oSC}_{j,u} \) is total DUoSC in tariff period u, due do each client type j

\( DU\text{oSC}_{j,k} \) is DUoSC of each network segment k in tariff period u due to each client type j

Where:

\[ DU\text{oSC}_{j,k} = CME \times \theta^{(k0,k)} \times PR_{j,k} \]

- \( PR_{j,k} \) is Peak Responsibility: contribution to peak (in percentage of client’s maximum demand) of each client i in each tariff period u in each network segment k;
- \( \theta^{(k0,k)} \) is load flow proportion that passes in each system segment k when 1 kW is requested at element k0 to which the client is connected.

The peak responsibility is the equivalent of a weighted average coincidence factor of each tariff period, added with cumulative power losses. More precisely, after calculating the coincidence factors of a client in each hour h with respect to the maximum demand of each network type, as well as the probabilities of the client to be served by each network type with maximum demand at hour h, the product of these factors is added up.

\[ PR_{j,k} = (1 + fpp^{(k0,k)}_{j,k}) \times \sum_{h \in u} \pi_{k,j} \times P_{j,h} \]

\( fpp^{(k0,k)}_{j,k} \) is cumulative power losses from the connection point of client k0 to network segment k, in tariff period u.
It is important to notice that if tariff periods are defined in advance, costs must be given in relation to the maximum demand of each tariff period. This way, the coincidence factor will be the client’s demand at hour h divided by his maximum demand during tariff period u.

**TIME-BASED LOCATIONAL DUOSC**

Brazil’s national electricity regulatory agency – ANEEL has calculated Transmission UoSC – in On-Peak and Off-Peak tariff periods using locational costs with two different generation dispatches: one for the period of maximum demand (On-Peak) and another for periods of medium demand (Off-Peak).

As one might expect, the result obtained for both tariff periods are very similar, because the values of ($\beta$$_i$$j$)(load flow variation in nodal methodology) change very little when only the dispatch is changed. It’s necessary to know the load curve of each network element and to verify in which of them maximum demand occurs in the On-Peak period, distinguishing them for those in which maximum demand occurs in the Off-Peak period.

For the calculation of On-Peak costs, one must only consider the unit costs off those network elements with maximum demand in the On-Peak period. The same applies to Off-Peak costs.

This is the fundamental concept applied in hourly cost calculation of distribution networks. This would be the basic modification necessary to obtain costs with economic logic, reflecting expansion cost effectively incurred when an additional 1 kW is requested in each tariff period. When a client requests an additional 1 kW in On-Peak period, only those networks with maximum demand in this period will have to be expanded. The networks with maximum demand in another time period won’t perceive any alteration in their maximum demand, and therefore no investments will be required.

The methodology for Hourly DUoSC explained before does this by considering the probability of clients to be associated with (served by) networks with maximum demand in each hour. The more networks there are with maximum demand in the On-Peak period, the greater will be the probability of association with these networks and the greater On-Peak cost will be. Taken to the extreme, if all networks have their maximum demand occurring in the On-Peak period, the probability of association and, therefore, the off-peak costs will be null, since $a$$_{h,eff}$ would be equal to zero, with no energy flowing through networks with maximum demand in Off-Peak periods.

Besides that, the methodology considers coincidence factors, cumulative power losses and a flow proportion $\varnothing$($k$,$k$), which in the locational methodology is given by $\beta$$_i$.$j$.

Therefore, the hourly locational UoSC methodology must incorporate the coincidence factor, or in other words, the client’s contribution to the networks peak demand, as well as cumulative power losses from his point of connection to each network element.

It isn’t necessary to consider the probability of association, since its calculation is deterministic for each user connected at each of the network busses (obtained by load flow).

Thus, the formulation of Time-Based Locational DUoSC should be as follows:

$$\pi_{j,h} = \sum_i \frac{C_i}{F P P_i} \times \beta_{i,j} \times (1 + f P P_h^{(j-i)}) \times P_{j,h}$$

$\pi_{j,h}$ = DUoSC when demanding or injecting 1 kW in bus j at hour h;

$C_i$ = Annual cost of the element i, in $/year;

$F P P_i$ = Capacity, in kW, of network element i;

$\beta_{i,j}$ = variation of the maximum demand of element i when 1 kW is demanded or injected at bus j at hour h;

$f P P_h^{(j-i)}$ = cumulative power losses from the connection point of client $k$ to network element i, at hour h;

$P_{j,h}$ = Coincidence factor: demand of client type $j$, at hour $h$, divided by his maximum demand in tariff period u.

**CALCULATION CRITERIA AND PROCEDURES**

The calculation of Time-Based Locational UoSC can be done alongside calculations of distribution network power and energy losses using the same tools and geo-referenced data as in Module 7 of ANEEL’s distribution procedures – PRODIST [7].

Information on the system’s physical data (networks, transformers, regulators, switches, meters, etc.) as well as energy consumption data from consumer units and generators, transformers and medium voltage feeders are obtained from the DSO’s geo-referenced database – BDGD.

The amounts of injected and supplied energy for each bus in the distribution system segments are the same as used for power loss calculation.

The load research data is the same as used for current Hourly DUoSC, retrieved in measurement campaigns. The period is the same as the one considered for loss calculation (annual). The criteria established for load flow simulation are also the same. Only the annual unit costs of each network element $C_i$ have to be included in the database.

Load flow simulations based on the procedures given in Module 7 of ANEEL’s distribution procedures – PRODIST [7] randomly attribute 3 load shapes (one work day, one Saturday and one Sunday) to each node of load or generation, thus building (bottom up) the load curves of each segment of distribution feeders, considering client’s load curves and losses. This attribution takes in account the category and a monthly energy consumption range of
each load or generator.

Although the software used (EPRI’s OpenDSS) doesn’t provide reports containing the load curves of each network segment out of the box, the flows through each network segment at each hour are calculated, which makes it possible to know the 3 load curves (work day, Saturday and Sunday) of each of the millions of network segment, from the client’s connection point up to the feeder in the substation, at which point the estimated load curve (built bottom up from load research data) can be compared to measured data.

Thus, it suffices to have an additional script that will:

i. Verify the time of maximum demand of each segment i;
ii. Calculate a coincidence factor (or contribution to peak factor) $P_{j,h}$ relative to each customer and each network segment i using the load curve obtained in item i together with the client’s load curve;
iii. Obtain the load flow $\beta_{j,h}$ in each network element i when 1 kW is requested on bus j.
iv. Calculate the cumulative loss factor $f_pp_{h(j-i)}$ from bus j to element i;
v. Calculate $\pi_{j,h}$ - Time-based Locational UoSC as formulated before.

Evidently, in each customer category there are clients with distinct load behaviour and the random choice of a load curve may not attribute a load shape to a specific bus that is exactly the same as the client’s. However, the closer one goes to the transformer or distribution feeder, the more this simulated load curve will resemble the real load curve and costs in each tariff period will become more consistent. Besides, one can always use more than one random selection, load flow simulation and UoSC calculation.

CONCLUSION

This article takes a first step towards calculating Time-Based Locational Use of System Costs, conceiving a conceptual basis of the methodology. Some simulations have already been performed with model networks, that would add robustness and intelligibility, but couldn’t be added to this document.

The next step in this research is, first, to develop a software that can compute Time-Based Locational UoSC for real case configurations of networks.

The final stage would be to create tariffs based on these costs distinguishing region and time of use, with different price signals varying in level and tariff periods.

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