# DISTRIBUTION NETWORK PRICING MODEL FOR EFFICIENT USE OF EXISTING INFRASTRUCTURE AND EFFICIENT NEW INVESTMENTS

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## *ABSTRACT*

*Electricity prices in Australia have been rising fast, and they are expected to grow further. The largest driver of these price increases have been increased spending on electricity distribution network. Non-network distributed energy resource (DER) alternatives such as demand response (DR) programs, energy storage (ES) devices and renewable based distributed generators (DGs) are expected to play an increasingly critical role in reducing spending on costly distribution network upgrades. However, DERs are in very early stage of being used by utility companies, investors and consumers in Australia mainly due to high cost of DERs. Therefore, both technology cost reductions, and a market framework that recognizes the multiple benefits of DERs are required to ensure the large scale deployment of DERs in Australia. This paper presents a model for estimating long run cost of distribution networks for the purpose of designing cost-reflective network pricing/ incentive scheme that will help promoting DERs.*

## INTRODUCTION

The electricity distribution network industry in many countries is facing a number of challenges. These include unsustainable large investment requirements in the network to replace ageing assets, meet growing levels of peak demand, reliability requirements and to facilitate the connection of more renewable generation to distribution networks. Efficient use of existing infrastructure and efficient investments in new infrastructure is the key to reduce this unsustainable spending in distribution networks. In many countries, existing tariff scheme which averages costs among network users and entirely based on energy volume does not send correct pricing signals to consumers and does not capture real cost of using existing network and investments in new assets. Correct pricing of customers for their use of distribution networks can play a key role in efficient use of existing networks and efficient investments in the presence of non-network distributed energy resources (DERs) such as distributed generators (DGs), energy storage (ES) devices and demand response (DR) programs.

## DISTRIBUTION NETWORK PRICING

The two main approaches that are widely discussed recently for distribution network pricing are “extent of use” method [1-2] and “long-run cost charging” method [3-5]. The extent of use method sets the tariff for distribution networks in order to recover fixed cost of existing distribution network assets by allocating costs to those who cause them in terms of time and location. Although extent of use based tariff promotes efficient use of existing assets, it does not send correct signals to users on their usage impacts on new investments. On the other hand, although long-run cost based distribution network charges provide forward looking messages on cost the users impose on future network investments, it does not send correct signal on efficient use of existing network. Therefore, a pricing approach that combines long run Incremental cost (LRIC) method and extent of use method would send correct signals to network users on cost they impose on the network.

There are very few studies on distribution network pricing approaches that combine LRIC and extend of use methods [6-7]. Well-developed methods are available for estimating extent of use based charges and those methods have been used in these two studies. However, these two studies have used simplified method to estimate LRIC of distribution networks. Simplified methods can underestimate the true LRIC of networks. Ideally, the estimation of LRIC of distribution should be done using a detailed network expansion planning exercises. In this context, we develop a framework for estimating LRIC of active distribution networks using a rigorous long-term distribution network expansion planning (LTDNEP) exercise. Further, some network areas in Australia are presently experiencing no load growth, in these areas efficient use of aging equipment can defer replacement cost of these equipment. In this scenario, we develop a methodology for calculating LRIC when there is no or low load growth in the network. This was done by incorporating loss-of-life cost of existing network equipment in its O&M cost and reliability cost as a function of loading level.

## ESTIMATING LRIC OF DISTRIBUTION NETWORKS

In this study we provide a framework for estimating location-specific LRIC of distribution network using a detailed network expansion planning exercise. Since, the distribution networks are now in the era of transition from passive networks to active distribution networks with the integration of DERs, future active distribution networks need more comprehensive planning methodologies and tools to develop least cost network expansion plans in the presence of DERs. We have developed a rigorous LTDNEP model for large active distribution networks under a research project titled “Planning Future Grids” in collaboration with an Australian distribution network service provider. The LTDNEP model is formulated as a mixed integer non-linear programming (MINLP) problem. The output of the model will describe the desired type of network (transformers, lines, voltage control devices) and non-network options (energy storage devices, DGs, DR programs) to be added, their capacity, the location, the years when the new capacities should be added during the planning period in order to meet the projected future demand at minimum cost. The objective function of the problem is to minimize the discounted cost of investments in network and non-network options, operation and maintenance costs, reliability cost as well as loss costs. The constraints of the problems are demand constraints for each portion of the load duration curve for each year for each node, maximum capacity constraints for each network and non-network devices, voltage constraints for each node. The mathematical formulation of LTDNEP problem is not presented here due to space limitation (see [8] for detailed problem formulation).

This proposed LTDNEP problem for real sized distribution networks involves a large number of variables and hence it is hard to solve this problem using exact mathematical methods. Due to the nature of Particle Swarm Optimization (PSO) as an optimization tool proven to be capable of handling highly non-linear and mixed integer problems, we apply heuristic optimization PSO to solve LTDNEP problem. However, in some cases, premature convergence and poor fine-turning of the final solution can occur in PSO. Therefore, in this study, we use a modified version of PSO (MPSO) by combining the strengths of PSO and GA to increase the diversity of variables and thereby to escape from local minima. In addition, the constriction factor approach for PSO [9] is applied in this algorithm because it has better performance compared to the inertia weight approach. Even with this heuristic method, computing good solutions to a LTDNEP problem of real-sized network remains a time consuming operation. Due to this factor, we use time decomposition technique forward backward approach to simplify the dynamic nature of the LTDNEP problem. The detailed description on solving LTDNEP problem for real-sized network using MPSO and forward-backward approach can be found in our earlier work in [10].

The methodology we use for calculating location specific LRIC of distribution networks using the LTDNEP model we developed is presented in Fig.1. On the left side of the flow chart, the procedure for estimating location specific LRIC of a distribution network without DR programs is presented. The right side of the flow chart shows how to incorporate DR in LTDNEP and how to estimate LRIC of a distribution network with DR.

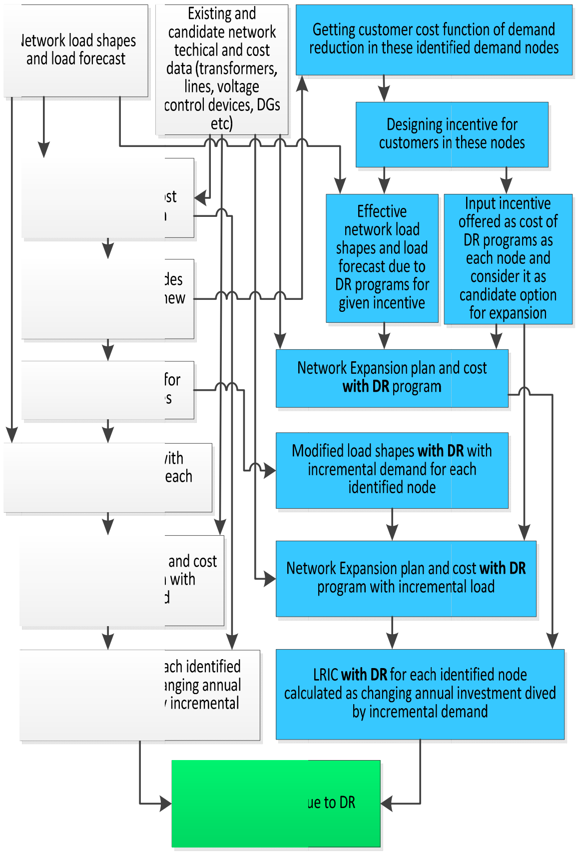


Fig.1: Framework for calculating LRIC with and without DR using a long-term network expansion planning Model

As shown in the Fig.1, once the network expansion plan for the base case is developed using the model we described above, the LRIC of the distribution network without DR for demand nodes that triggers new investment can be calculated by giving incremental load to the selected nodes and developing expansion plans again. The LRIC is equal to annuity of change in PV of expansion cost divided by incremental load. To estimate the LRIC with DR programs, first we develop a new network expansion plan by considering DR programs as a candidate option for network expansion along with other candidate network options. The incentive value that can compensate customers adequately to cover their costs and bring the required demand reduction is estimated using the customer demand reduction cost function at each selected node. This new least cost expansion plan provides the information on cost-effective DR programs that maximize utility’s benefits while compensating customers for their lost service at each selected node. Then, as shown in the figure, following the same methodology for estimating LRIC without DR, the LRIC with DR for demand nodes that triggers new investment can be calculated by giving incremental load to selected node and developing expansion plans again.

In our approach described above, we assume that the network demand continuously growing over time and examine how a nodal increment in demand would change the timing of new investments in the network and then this time change is translated to tariffs. Therefore, this approach is not applicable to the network areas presently experiencing low or no load growth. Since the demand management can defer replacement of aging equipment in these areas, in a future study we intend to present a detailed methodology of estimating LRIC of distribution networks by considering not only the time change of new investment to meet positive load growth but also the time change in replacement of existing aging equipment due to demand management. This will be achieved by incorporating loss-of-life cost of existing network equipment in its O&M cost and reliability cost as a function of loading level. The detailed mathematical formulation for this will be given in a forthcoming paper.

## CASE STUDY

In the present study, we illustrate the application of the rigorous approach we developed for estimating location specific LRIC for a realistic 747-bus distribution network in Queensland with and without DR. This network includes four zone substations (66/11 kV) with 33 outgoing 11 kV feeders, 473 distribution transformers, and 742 line branches. The total length of 11 kV feeders is about 130 km. The total number of premises in this area are 16253, including 13363 residential, 2565 commercial, and 325 industrial customers. One of 4 zone substations and corresponding distribution network is depicted in Fig. 2.

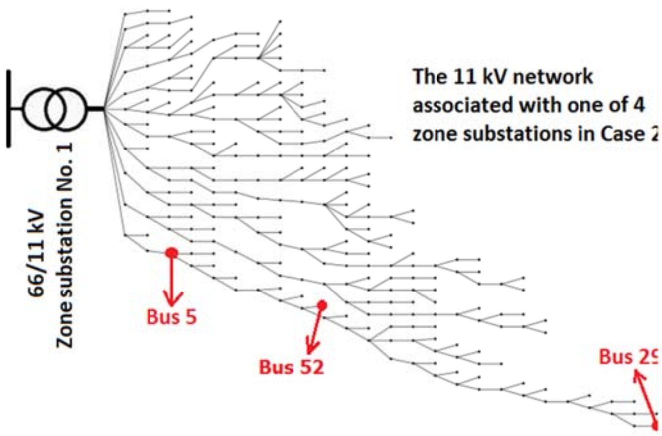


Fig. 2. Zone substation No. 1 and the corresponding distribution network.

### Estimating LRIC without DR

To estimate the LRIC of selected buses without DR, we first developed the long term network expansion plan for the base case that is for current given demand data at each bus for first year with 4% annual load growth by considering transformers, lines, capacitors and voltage regulators as candidate options for network expansion. The long-run network expansion plan for the base case given in Table I shows that total of 19388kVA of distribution transformers, and 6600 kVA of capacitors would be added to the network to meet the projected demand during the 5 year planning period. The total discounted cost of network expansion plan of the base case is found to be AUS$ 172.793 million.

We selected bus 29 to estimate the location specific LRIC. For this purpose, we developed another network expansion plan by giving 50kW increment to first year demand at bus 29 keeping the same load growth of 4% for remaining years for bus 29 and keeping the same demand for other buses. Table II gives the new network expansion plan. When the demand at bus 29 is increased by a 50kW, the least cost network expansion planning analysis shows that 716 kVA of additional distribution transformer capacity and 231 kVA of less capacity of capacitors would be added in the system compared to the base case. These changes would result in total discounted cost of network expansion plan to increase to AUS$ 173.393 million as compared to AUS$ 172.793 million for the base case. Thus the total discounted cost increment during the planning period would be AUS$ 600,000 and the corresponding annual unit LRIC (with annuity factor of 0.23) would be AUS$ 2771/kW.

Table 1. Least cost network expansion plan for Base case without DR

| year | Capacity additions by network option type | | NPV cost (k$) |
|---|---|---|---|
| | T/F (kVA) | Cap. (KVA) | |
| 1 | 17633 | 4786 | - |
| 2 | 0 | 0 | - |
| 3 | 539 | 1383 | - |
| 4 | 500 | 662 | - |
| 5 | 0 | 0 | - |
| Total | 18672 | 6831 | 172793 |

Table 2I. Least cost network expansion plan with 50kW demand increment at bus 29 without DR

| year | Capacity additions by network option type | | NPV cost (k$) |
|---|---|---|---|
| | T/F (kVA) | Cap. (KVA) | |
| 1 | 18223 | 4532 | - |
| 2 | 0 | 0 | - |
| 3 | 565 | 1967 | - |
| 4 | 600 | 101 | - |
| 5 | 0 | 0 | - |
| Total | 19388 | 6600 | 173393 |

### Estimating LRIC with DR

In this section, we estimate the LRIC at bus 29 by considering DR as candidate option for network expansion. For this purpose, least cost network expansion planning exercise is carried out by considering DR programs as candidate options for network expansion along with other candidate network options. As described in the methodology section, the incentive offered to DR is considered as the cost of DR and demand reduction due to DR is incorporated in the model by modifying total demand at bus with DR as total demand in the base case net of the given demand reduction profile of DR. The least cost network expansion plan for DR case is presented in Table III. As shown in the table, it is cost-effective to implement DR programs at 4470 residential premises in this network area during the 5 year period. That is, total cost-effective residential DR penetration is about 33%. This level of DR program penetration would reduce 1951 kVA of distribution transformer addition during the planning period compared to base case, while increasing the capacitor addition by 320 kVA. The total NPV cost of network expansion plan of this network area without the DR is found to be AUS$172. 793 million as compared to AUS$ 172.295 million when DR program in 4470 premises are included in the system during the planning period. Thus the total discounted avoided network cost due to DR during the planning period would be AUS$ 498000.

Table III. Least cost network expansion plan for DR case

| year | Capacity additions by network option type | | | NPV cost (k$) |
|---|---|---|---|---|
| | T/F (kVA) | DR programs (no. of customers ) | Cap (KVA) | |
| 1 | 15907 | 2472 | 5811 | - |
| 2 | 0 | 0 | 0 | - |
| 3 | 251 | 1899 | 1257 | - |
| 4 | 563 | 100 | 83 | - |
| 5 | 0 | 0 | 0 | - |
| Total | 16721 | 4470 | 7151 | 172295 |

How would DR program change the LRIC of the network? To answer this question, we calculated LRIC of bus 29 with DR. For this purpose, we carried out another network expansion planning exercise by giving a 50kW demand increment to bus 29 by considering DR program as candidate options alongside other network options. The lest cost expansion planning with DR with a 50kW demand increment at bus 29 shows that it would increase the total NPV cost of network expansion plan to AUS$ 172.451 million from AUS$ 172.295 million. Thus, total discounted value of increase cost during the planning period due to demand increase would be AUS$156000. The unit annual LRIC at bus 29 with DR is estimated to be AUS$ 718/kW. This present analysis shows that the DR could reduce the network expansion cost and hence the LRIC.

## KEY FINDINGS AND FINAL REMARKS

This paper presents a detailed distribution network expansion planning model for large active distribution networks which we developed under a research project titled “Planning Future Grids” in collaboration with an Australian distribution network service provider. It also presented a rigorous methodology for estimating LRIC of distribution networks using the proposed model. It has also applied the methodology to estimate the LRIC of a realistic 747-bus distribution network in Queensland, Australia with and without DR. Our analysis illustrates that our proposed detailed distribution network expansion planning model can be used not only for development of network expansion plans but also for determining optimal cost-effective penetration levels of non-network options, avoided network cost due to non-network options, and estimating LRIC of distribution networks.

In the present study, we estimated LRIC of a selected node in the network to illustrate the applicability of our methodology for estimating LRIC of large distribution network. We intend to do a comprehensive study to estimate the LRIC of all nodes. Since development of long-term network expansion plans for large network is time consuming, it would be highly time consuming to estimate LRIC for each and every bus in the real size large distribution networks. Therefore, in a future study, we intend to develop a preprocessing approach to find load nodes which are highly cost sensitive to demand changes based on thermal limits and or voltage violation of individual nodes so LRIC is calculated for those highly cost sensitive nodes only. Furthermore, some network areas in Australia are presently experiencing low or negative load growth. In this scenario also DERs can play critical role in reducing the cost of replacing the aging equipment. Existing approaches on valuing long run network costs are developed assuming that there will be a positive load growth always, and LRIC is estimated based on growth related network investments. Therefore, these existing methods would not be applicable to this new trend in distribution networks in Australia. With regard to this, we intend to develop a new approach of estimating location specific LRIC of networks when these is a low load growth. This will be achieved by incorporating loss-of-life cost of existing network equipment in its O&M cost and reliability cost as a function of loading level.

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