

## Comprehensive Long-Run Incremental Cost (LRIC)-Voltage Network Pricing Approach to Support Network Voltages Given Contingencies

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**Abstract:** most network charges are based on components' thermal limits providing correct economic signals to reinforcing network transformers and lines. However, less attention is drawn to the reinforcement cost driven by nodal voltage limits, particularly those resulting from contingencies. In this work, a new charging approach is proposed in which busbar power perturbation is linked to busbar voltage degradation rate which, in turn, is related to the incremental investment cost required to maintain voltage levels. The incremental cost results by employing the use of the nodal voltage spare capacity to gauge the time to invest in a reactive power compensation device for a defined load growth rate. The time to invest takes into account the network nodal voltage profiles under N-1 circuit contingencies (one line outage at a time). Further, the nodal MW and MVar perturbations are considered in this paper. This novel approach is demonstrated on the IEEE 14 bus network, illustrating the difference in charges when considering contingencies, therefore, providing correct forward-looking economic signals to potential network users. In turn, this will help them make informed decisions as to whether to invest in reactive power compensation assets or pay the network operators for reactive power provision. Most importantly, this new approach outperforms the currently used power factor (pf) penalty.

**Index Terms:** Base LRIC-voltage network charges, CF LRIC-voltage network charges, lower Nodal Voltage Limit, Upper Nodal Voltage Limit, Contingency Factors, Spare nodal voltage capacity and VAr compensation assets.

### I. INTRODUCTION

ONE of the fundamental requirements for network operators is to ensure that network nodal voltages are within prescribed limits. The natural way of achieving this is by having reactive power sources (static and dynamic devices) distributed through-out the entire network during its steady state operation and when its experiencing credible contingencies. The extent at which this can be achieved is sometimes limited by the availability of funds. In this regard, reasonable funding can be used to install just adequate reactive power sources and, then as a measure of enhancement, an appropriate economic model can be used to charge for the use of the network reactive power compensation assets to ensure that network voltages are within predetermined limits. Also, it should be noted that it is a requirement for network operators to operate their infrastructure subject to N-1 circuit contingencies (outage of each line at a time) to guarantee that it operates reliably and securely. This is even more important under the prevailing worldwide trend of privatization and

Restructuring of the respective power systems as voltage instability incidents

Have been experienced in a number of countries. These, at times, led to several major voltage collapse scenarios. The Aforementioned voltage instability is due to power systems operated tightly to their transmission capability limits against the backdrop of economic and environmental concerns. The problem is often compounded by delays in developing transmission lines resulting from lengthy and complex approval processes, particular regarding interconnected independent power systems. These aforementioned effects make it difficult to master the control of reactive power demand and, hence, difficult to retain network nodal voltages within prescribed limits.

Most research in reactive power pricing [1]-[12] reflects the operational cost related to reactive power due to new customers, i.e. how they might affect network losses. Also, network reactive power pricing has generated substantial research interests into methodologies to reflect investment costs incurred in network when supporting nodal real and reactive power injection/withdrawal [13], [14]-[33], however, the network investment costs are restricted to the circuits and transformers triggered by thermal limits. Further, this investment does not account for contingencies. The investment cost-related price (ICRP) charging model [34] used in the UK does not consider the network security requirement in the model, but it relies on post-processing through a full-contingency analysis to give an average security factor of 1.86 for all concerned network assets. Based upon those latter methodologies, particularly those in [20], [26] and [30], the first approach to charge for the cost of supporting network nodal voltages was developed [35], but does not consider the effect on the reinforcement cost from contingencies, hence, it does not consider the additional stress to the network when contingencies occur. Further, authors of [36] presented a study on the approach on [35] i.e. LRIC-voltage network charges given different network R/X ratios to demonstrate the practical reality of a network ranging from a transmission to distribution infrastructure. On the other hand, authors of [37]-[40] considered the N-1 contingency analysis into their charging principles and all of these were for pricing of network circuits and transformers based on the thermal use of the network. Paper [14] demonstrated a simplistic approach to account for N-1 contingencies based on the assumption that reinforcement is required when a branch thermal power flow reaches 50% of its capacity. Therefore, it is against this background that in this research an approach that factor in the effect of N-1 contingencies in the LRIC-voltage network charging model in proposed.

This paper is concerned with development of network charges that account for reinforcement cost triggered by busbar voltage limits under N-1 contingencies. Further, these are compared with those under normal conditions of the network. This charging principle employs the use of the unused nodal voltage capacity or headroom within an existing network to gauge time to invest in reactive power compensation device for each node in the system. A nodal withdrawal/injection of real/reactive power will impact on the nodal voltage, which in turn impact on the time to reinforce reactive power compensation devices. LRIC-V network charges are the difference in the present value of future Var compensation devices with and without the nodal perturbation, providing an economically efficient forward-looking pricing signal to influence the siting and/or reactive power consumption of demand and generation for bettering network voltage profile. It should be noted and emphasized that this paper demonstrates the charging model at nodes without VAR compensation assets (future VAR assets) and later (not part of this paper) this undertaking would be extended to nodes with compensation assets (existing VAR assets). Ultimately, the reactive power planning (RPP) problem (also, not part of this paper) would be integrated with the LRIC-voltage network pricing approach, to price for the future and the existing network VAR compensation assets as the most practical approach to employ. In this case, N-1 circuit contingencies should be considered.

This paper is organized as follows: Section II details the mathematical models of the LRIC-voltage network charging (base LRIC) principle under normal state and the impact to network voltages when considering N-1 contingencies and the resulting LRIC-voltage network charging formulation considering N-1 contingencies (CF LRIC). Section III provides comparison and analyses of LRIC-voltage charges with and without considering N-1 contingencies on an IEEE 14 bus network. The paper's conclusions are drawn in Section IV. Section V provides for Appendix which outlines the loading condition of the test system while References are depicted in Section VI...

**II. MATHEMATICAL FORMULATION OF LONG-RUN INCREMENTAL COST PRICING BASED ON NODAL SPARE CAPACITY**

The LRIC-V network charging principle is based upon the premise that for an assumed nodal generation/load growth rate there will be an associated rate of busbar voltage degradation. Given this assumption the time horizon for a busbar to reach its upper /lower voltage limit can be evaluated. Once the limit has been reached, a compensation device will be placed at the node as the future network reinforcement to support the network voltage profiles. A nodal demand/generation increment would affect the future investment horizon. The nodal voltage charge would then be the difference in the present value of the future reinforcement consequent to voltage with and without the nodal increment

In this section, the nodal base LRIC-V network charging principle formulation would be outlined. Thereafter, the formulation to reflect the nodal voltage impact on buses

resulting from N-1 contingencies would be shown. Finally, this effect of N-1 contingencies would be factored into the former charging principle to constitute CF (contingency factor) LRIC-voltage network charges.

**A. Base LRIC-Voltage Network Charging Principle**

The following steps outlined below can be utilized to implement this charging model:

**1) Evaluating the future investment cost of network VAR compensation assets to support existing customers**

If a network node  $b$ , has lower voltage limit,  $V_L$  and upper voltage limit  $V_H$ , and holds a voltage level of  $V_b$ , then the number of years for the voltage to grow from  $V_b$  to  $V_L / V_H$  for a given voltage degradation rate  $v_r$  can be evaluated from (1.a) or (1.b).

If  $V_L$  is critical, i.e, bus voltage is less than target voltage, 1 pu :

$$V_L = V_b \times (1 - v_r)^{n_{bL}} \tag{1.a}$$

On the other hand if  $V_H$  is critical, i.e, bus voltage is more than target voltage, 1 pu :

$$V_H = V_b \times (1 + v_r)^{n_{bH}} \tag{1.b}$$

Where:  $n_{bL}$  and  $n_{bH}$  are the respective numbers of years that takes  $V_b$  to reach  $V_L / V_H$ .

Reconfiguring equations (1.a) and (1.b) constitute:

$$(1 - v_r)^{n_{bL}} = \frac{V_L}{V_b} \tag{2.a}$$

$$(1 + v_r)^{n_{bH}} = \frac{V_H}{V_b} \tag{2.b}$$

Then the values of  $n_{bL} / n_{bH}$  are

$$n_{bL} = \frac{\log V_L - \log V_b}{\log(1 - v_r)} \tag{3.a}$$

$$n_{bH} = \frac{\log V_H - \log V_b}{\log(1 + v_r)} \tag{3.b}$$

The assumption is that when the node is fully loaded the reinforcement will take effect. This means that investment will be effected in  $n_{bL} / n_{bH}$  years when the node utilization reaches  $V_L / V_H$ , respectively. At this point an installation of a VAR compensation asset is regarded as the future investment that will be needed at the node to support the voltage.

**2) Determining the present value of future investment cost**

For a given discount rate of  $d$ , the present value of the future investment in  $n_{bL}/n_{bH}$  years will be:

$$PV_{bL} = \frac{Asset_{CbL}}{(1+d)^{nbL}} \quad (4.a)$$

$$PV_{bH} = \frac{Asset_{CbH}}{(1+d)^{nbH}} \quad (4.b)$$

Where  $Asset_{CbL}$  and  $Asset_{CbH}$  are the modern equivalent asset cost to cater for supporting voltage due to lower voltage limit and upper voltage limit violations, respectively.

### 3). Deriving the incremental cost as a result of an additional power injection or withdrawal at node N

If the nodal voltage change is  $\Delta V_{bL}/\Delta V_{bH}$  consequent upon an additional  $\Delta Q_{In}$  withdrawal/injection at node N, this will bring forward/delay the future investment from year  $n_{bL}/n_{bH}$  to  $n_{bnewL}/n_{bnewH}$  and when  $V_L$  is critical

$$\text{For withdrawal } V_L = (V_b - \Delta V_{bL}) \times (1 - v_r)^{n_{bnewL}} \quad (5.a)$$

or

$$\text{For injection } V_L = (V_b + \Delta V_{bH}) \times (1 - v_r)^{n_{bnewL}} \quad (5.b)$$

And when  $V_H$  is critical

$$\text{For withdrawal } V_H = (V_b - \Delta V_{bL}) \times (1 + v_r)^{n_{bnewH}} \quad (5.c)$$

or

$$\text{For injection } V_H = (V_b + \Delta V_{bH}) \times (1 + v_r)^{n_{bnewH}} \quad (5.d)$$

Equations (6.a), (6.b), (6.c) and (6.d) give the new investment horizons as

$$n_{bnewL} = \frac{\log V_L - \log(V_b - \Delta V_{bL})}{\log(1 - v_r)} \quad (6.a)$$

or

$$n_{bnewL} = \frac{\log V_L - \log(V_b + \Delta V_{bH})}{\log(1 - v_r)} \quad (6.b)$$

$$n_{bnewH} = \frac{\log V_H - \log(V_b - \Delta V_{bL})}{\log(1 + v_r)} \quad (6.c)$$

or

$$n_{bnewH} = \frac{\log V_H - \log(V_b + \Delta V_{bH})}{\log(1 + v_r)} \quad (6.d)$$

Then the new present values of the future investments are

$$PV_{bnewL} = \frac{Asset_{CbL}}{(1+d)^{nbnewL}} \quad (7.a)$$

$$PV_{bnewH} = \frac{Asset_{CbH}}{(1+d)^{nbnewH}} \quad (7.b)$$

The changes in the present values as consequent of the nodal withdrawal/injection  $\Delta Q_{In}$  are given by (8.a) and (8.b)

$$\Delta PV_{bL} = PV_{bnewL} - PV_{bL} \quad (8.a)$$

$$\Delta PV_{bH} = PV_{bnewH} - PV_{bH} \quad (8.b)$$

The annualized incremental cost of the network items associated with component  $b$  is the difference in the present values of the future investment due to the reactive power magnitude change  $\Delta Q_{In}/\Delta P_{In}$  at node N multiplied by an annuity factor

$$IV_{bL} = \Delta PV_{bL} * \text{annuityfactor} \quad (9.a)$$

$$IV_{bH} = \Delta PV_{bH} * \text{annuityfactor} \quad (9.b)$$

### 4) Evaluating the long-run incremental cost

If there are a total of  $bL$  busbars' lower limits and  $bH$  busbars' high limits that are affected by a nodal increment from  $N$ , then the LRIC-V network charges at node  $N$  will be the aggregation of the changes in present value of future incremental costs over all affected nodes:

$$LRIC_{-VN,L} = \frac{\sum_{bL} IV_{bL}}{\Delta Q_{In} / \Delta P_{In}} \quad (10.a)$$

$$LRIC_{-VN,H} = \frac{\sum_{bH} IV_{bH}}{\Delta Q_{In} / \Delta P_{In}} \quad (10.b)$$

### B. Impact to Network Voltage When Considering N-1 Contingencies

If a network node  $b$  supports voltage  $V_b$  under the normal state and has to carry an additional voltage of  $\Delta V_L$  due to the most severe N-1 contingency situation, then the contingency factor at that node can be determined by (11)

$$CF_L = \frac{V_b + \Delta V_L}{V_b} \quad (11)$$

Given the node has to withstand additional voltage disturbance, where the magnitude of the disturbance is indicated by contingency factor,  $CF_L$ , the system cannot be allowed to operate to its limits. Instead, the maximum

allowed voltage level at each busbar has to be modified to cater for potential contingencies. This new nodal voltage limit for the lower bus voltage limit can be determined by (12)

$$V_{bcf_L} = \frac{V_L}{CF_L}$$

(12)

On the other hand, if a network node b supports voltage  $V_b$  under normal state and has to carry an additional voltage of  $\Delta V_H$  due to the most severe N-1 contingency situation, then the contingency factor at that node can be determined by (13)

$$CF_H = \frac{V_b + \Delta V_H}{V_b}$$

(13)

Given the node has to withstand additional voltage disturbance, where the magnitude of the disturbance is indicated by contingency factor,  $CF_H$ , the system cannot be allowed to operate to its limits. Instead, the maximum allowed voltage level at each busbar has to be modified to cater for potential contingencies. This new nodal voltage  $V_{bcf_H}$  limit for the higher bus voltage limit can be determined by (14)

$$V_{bcf_H} = \frac{V_H}{CF_H}$$

(14)

### C. CF LRIC-Voltage Network Charges

Given the newly determined network lower bus limit,  $V_{bcf_L}$ , and higher bus limit,  $V_{bcf_H}$ , to support N-1 contingencies, these can be utilized in the LRIC-v charging principle to formulate the CF LRIC-voltage network charges by replacing  $V_L$  by the former new limit while replacing  $V_H$  by the latter new limit in the relevant equations above.

## III. IMPLEMENTATION

### 1. Test System

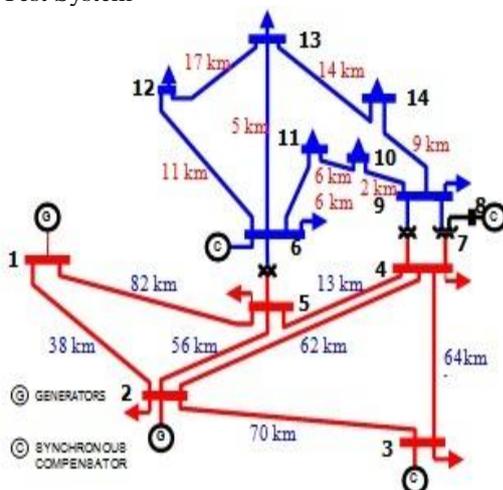


Fig. 1: IEEE 14 Bus System

The test system shown above in Fig. 1 is the IEEE 14 bus network, the load and generation data of this network are shown in the appendix section. This network consists of 275kV sub transmission voltage level shown in red and the 132kV distribution voltage level shown in blue. There are two generators and three synchronous compensators. The synchronous compensators boost the voltage at buses 3, 6, 8 since the subtransmission lines are fairly long. It is also worthwhile to note that, these synchronous compensators have reached their full capacities and, therefore, they cannot maintain their respective bus voltages at pre-set voltage levels and, as such, during withdrawals/injections, voltage changes are experienced at the buses where these are connected. The line distances between the buses are depicted in blue and red for the sub transmission and distribution levels, respectively. The compensation assets (SVCs) have the investment costs of £1, 452,000 and £696, 960 at the 275-kV and 132-kV voltage levels, respectively.

Bus 1 is the slack bus. The voltage limits are assumed to be  $1 \pm 6\%$  pu. The use of power flow was employed to capture the nodal voltages while performing nodal withdrawals/injections on the system. The annual load growth for this test network is assumed to be 1.6% while the discount rate is assumed to be 6.9%.

### A. Base LRIC-Voltage Network Charges

The base LRIC-v network charges are determined by injecting/withdrawing 1 MVar/1 MW at every node of the system without subjecting the system to N-1 contingencies.

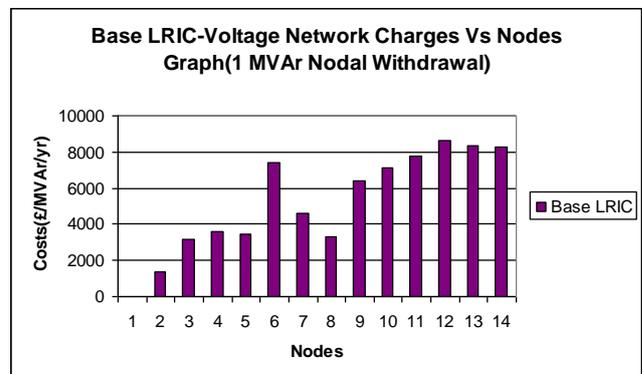


Fig. 2: Base Nodal LRIC-Voltage Network Charges per MVar withdrawal

Buses 2, 7 and 8 have their initial voltages greater than the target voltage of 1 pu while the rest of buses excluding the slack bus have their initial voltages below 1 pu.

Withdrawing reactive power would help buses 2, 7, and 8 to be closer to the target voltage, thus should be rewarded for increasing the margins of the already critical busbar upper voltage limits. Customers at these buses are incentivized to take reactive power from the network as the investment horizons of the VAr compensation assets at the respective bus are deferred. While the rest of the buses excluding the slack bus are penalized for reactive power withdrawal as it decrease the margins to the lower voltage limits since this action advance the investment horizons of the VAr compensation assets at the study bus. Although individual busbars may have charges or credits against the

same nodal withdrawal, the nodal LRIC-voltage network price in this system is a charge against each node, since the price accounts for the system wide effects from a nodal withdrawal, the credits from buses 2, 7 and 8 are far less than the accumulated charges from the rest of the busbars.

It can also be observed that the LRIC-voltage network charges generally increase with increasing distance. Bus 3 has the largest distance but the charge is comparably small, This is because the bus is connected with a synchronous Condenser which boosts the voltage at that bus. The same occurs at bus 6 and 8. The charge at bus 8 is smaller than at bus 7 since bus 8 has its voltage boosted. Even though Bus 14 has a larger distance than buses 12 and 13, as withdrawing from this node has a larger impact to buses 7 and 8 which earn larger credit contributing to reduced overall charge. The same applies to bus 13 since it is closer to buses 7 and 8 than bus 12. Bus 12 under the aforementioned circumstances attracts the most charge since it is further from buses 7 and 8 than buses 13 and 14 resulting in less credit at buses 7 and 8 in contribution to the overall higher charge at this bus. Bus 2 has the least charge since it is closer to the slack bus.

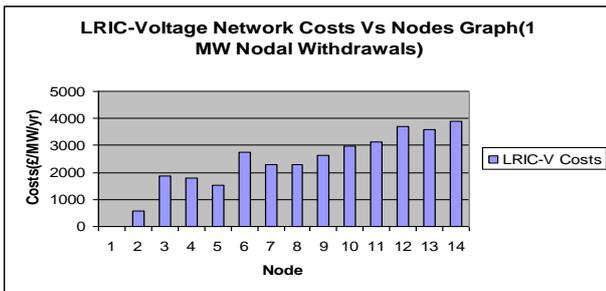


Fig. 3: Base LRIC-Voltage Network Charges due to 1MW nodal withdrawal

As it can be observed from Fig. 3, the LRIC-v charges follow the same pattern as those of MVar nodal withdrawals in Fig. 2 since the conditions are the same as the latter case, in terms of, respective nodal distances from the slack bus and the initial voltages before nodal withdrawals. However, during the MW withdrawals, the nodal voltages are degraded less than in the case with MVar withdrawals and, hence, less resulting LRIC-v network costs. This owes to the fact that the resulting network circuit reactance (X) is more than the resulting network circuit resistance (R).

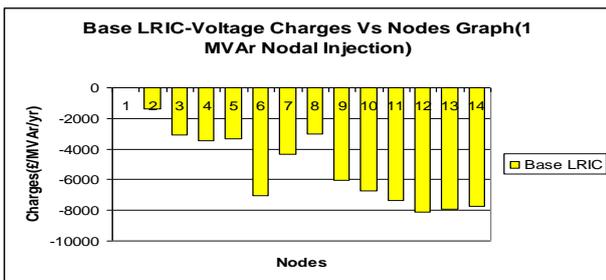


Fig. 4: Base LRIC-Voltage Network Charges due to 1MVar nodal injections

Fig. 4 shows benefits against buses given 1 MVar nodal injections.

During nodal injections, the buses (2, 7 & 8) having their initial voltages above 1 pu are penalized for degrading the already critical busbar upper voltage limits while the rest except the slack bus are credited for relieving the already critical busbar lower voltage limits. The same reasons as for nodal withdrawals hold as the overall result is that all buses earn credits. Also, observed is that the credits increase as distances increase. The conditions in this case are the same as for the previous case of Fig.2, therefore, the pattern remains the same, in that, Bus 12 attracts the most credit while Bus 2 attracts the least.

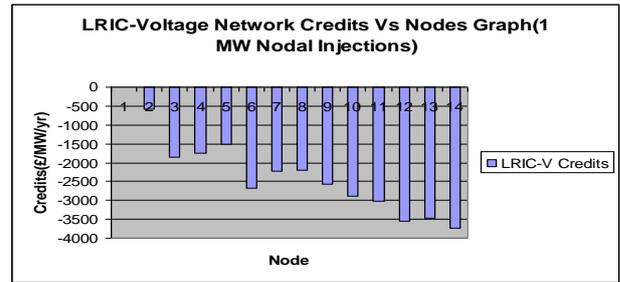


Fig. 5: Base LRIC-Voltage Network Charges due to 1MW nodal injections

It can also be observed from Fig. 5, that the LRIC-v charges follow the same pattern as those of MVar nodal injections, but with less LRIC-v credits for the same reasons relating to the differences depicted above for the MVar and MW withdrawals.

**B. Contingency Factor Terms**

The nodal contingency factors reflect additional voltage change that would be incurred following the worst contingency. Since every network bus has both the lower and upper limits, the contingency factors to cater for both of these limits on each bus were determined, subject to N-1 contingencies.

Fig. 6 and TABLE 1 show lower voltage limit contingency factors against nodes. In addition, TABLE 1 shows initial, and outage voltages and the resulting lower nodal voltage limits.

On the other hand, Fig. 7 and TABLE 2 show higher Voltage limits contingency factors against nodes. In addition, TABLE 2 shows initial, and outage voltages and the Resulting higher nodal voltage limits.

**1. Test System CF<sub>L</sub>**

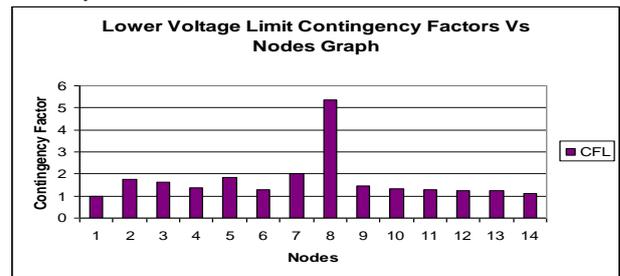


Fig. 6: IEEE 14 bus system lower voltage limit contingency factors at each node

TABLE 1

LOWER NODAL VOLTAGE LIMIT CONTINGENCY FACTORS  
 SUBJECT TO N-1 CONTINGENCIES

Bus	Initial Voltage (pu)	Outage Voltage (pu)	CF <sub>L</sub>	Resulting VL (pu)
1	1.03	1.03	1	0.94
2	1.02	0.99	1.752	0.992
3	0.996	0.954	1.646	0.987
4	0.988	0.962	1.374	0.973
5	0.995	0.941	1.83	0.994
6	0.982	0.96	1.284	0.967
7	1.008	0.955	2.015	1.000
8	1.048	0.998	5.345	1.038
9	0.981	0.947	1.442	0.977
10	0.974	0.946	1.314	0.969
11	0.974	0.95	1.281	0.966
12	0.967	0.945	1.244	0.964
13	0.963	0.94	1.239	0.963
14	0.954	0.943	1.099	0.951

HIGHER NODAL VOLTAGE LIMIT CONTINGENCY FACTORS  
 SUBJECT TO N-1 CONTINGENCIES

Bus	Initial Voltage (pu)	Outage Voltage (u)	CF <sub>H</sub>	Resulting VH (pu)
1	1.03	1.03	1	1.06
2	1.02	1.02	1.001	1.060
3	0.996	1	1.081	1.051
4	0.988	0.989	1.02	1.058
5	0.995	0.999	1.07	1.052
6	0.982	0.986	1.088	1.050
7	1.008	1.052	1.644	1.013
8	1.048	1.056	1.068	1.052
9	0.981	0.992	1.268	1.035
10	0.974	0.977	1.097	1.049
11	0.974	0.975	1.029	1.057
12	0.967	0.971	1.12	1.047
13	0.963	0.968	1.222	1.038
14	0.954	0.955	1.089	1.050

Fig. 6 shows a plot of CF<sub>L</sub> values against nodes given the most severe N-1 contingency condition impacting on each lower voltage bus limit on the IEEE 14 bus test system. TABLE 1 also shows the CF<sub>L</sub> values against nodes and in addition the initial voltages before the outages, the outage voltages and the resulting new lower voltage limits.

The largest CF<sub>L</sub> is recorded at bus 8. The most severe outage on this bus was when the line between buses 2 and 3 is outaged. This particular line was critical in supplying the necessary apparent power to support the load at bus 3. During this outage, all the apparent power had to be re-routed along the line between buses 3 and 4. This caused the voltage at bus 8 to drop from 1.048 pu to 0.998 pu which corresponds to a bus loading variation from 9.73% to 52% with respect to the lower voltage limit. The CF<sub>L</sub> value at bus 7 is the second largest since both aforementioned buses were severely affected by the same outage. The least CF<sub>L</sub> value is at the slack bus since the voltage at this bus remains the same across all the outages.

The results generally show that the more the CF<sub>L</sub> values the more reduced the resulting nodal lower voltage limits.

Fig. 7 shows a plot of CF<sub>H</sub> values against nodes given the most severe N-1 contingency condition impacting on each higher voltage bus limit on the IEEE 14 bus test system. TABLE 2 also shows the CF<sub>H</sub> values against nodes and in addition the initial voltages before the outages, the outage voltages and the resulting higher voltage limits.

The largest CF<sub>H</sub> value is recorded at bus 7. The most Severe outage on this bus is when the line between buses 7 and 9 was taken out. This outage resulted in a large voltage rise at this bus since this line was critical in linking the sub Transmission and most of the distribution side of the network. Due to this outage the power was re-routed from the line connecting the slack bus to bus 5 and eventually from bus 5 through to bus 6 through the transformer to other buses. The voltage rised from 1.008 Pu to 1.052 Pu This constituted bus loading variation from 56.67% to 93.17% with reference to the higher voltage limit. The least CF<sub>H</sub> value is also at the slack bus since the voltage at this bus remains the same across all the outages.

The results generally show that the more the CF<sub>H</sub> values the more reduced the resulting nodal higher voltage limits.

2. Test System CF<sub>H</sub>

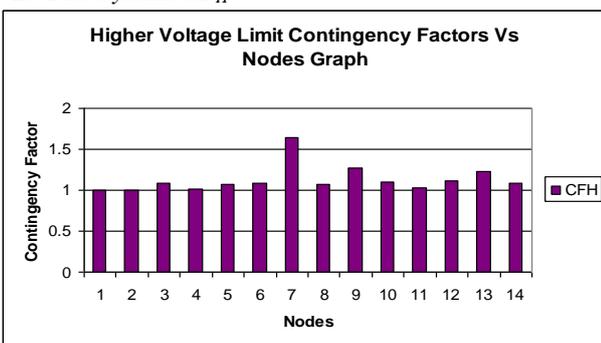


Fig. 7: IEEE 14 bus system higher voltage limit contingency factors at each node

TABLE 2`

C. CF LRIC-Voltage Network Charges

After calculating the contingency factors for the corresponding lower and higher nodal voltage limits then the CF LRIC-voltage network charges were determined based on those new limits.

Fig. 8 and Fig. 9 show CF LRIC-voltage network charges due to 1 MVar and 1MW nodal withdrawals, respectively. On the other hand, Fig. 10 and Fig. 11 show CF LRIC-voltage network charges due to 1 MVar and MW nodal injections, respectively.

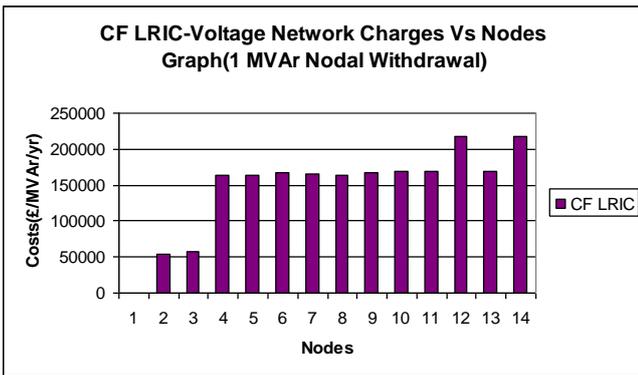


Fig. 8: CF LRIC-voltage network charges due to 1 MVar withdrawal at each node

Since the lower nodal voltage limit margins have been reduced to support N-1 contingencies, during nodal withdrawals, a number of lower voltage limits have been reached therefore reinforcements indications were as follows:

- 1) During withdrawals at buses 2 and 3, the lower voltage limit at bus 13 was reached; therefore, a reinforcement cost was attracted at this bus. At other buses during these respective withdrawals, some attracted credits (buses 2, 7 and 8) while the rest excluding the slack bus attracted costs for degrading the respective lower voltage limit margins. Since bus 3 has more distance from the slack bus it attracted more cost than bus 2.
- 2) During withdrawals at buses 4, 5, 6, 7, 8, 9, 10, 11 & 13 there were lower voltage limit violations at buses 5, and 13, as such, these attracted reinforcement costs.
- 3) During withdrawal at bus 12, buses 5, 12 and 13 had their lower voltage limits reached and, as such, attracted reinforcement costs.
- 4) Lastly, during withdrawal at bus 14, buses 5, 13 and 14 had their lower voltage limits reached; therefore, they attracted some reinforcement costs.

Since buses 12 and 14 attracted three reinforcement costs have their costs around £218,000.00 while buses 2 and 3 have the least costs around £55,000.00 and £58,000.00 respectively since they attracted only one reinforcement costs.

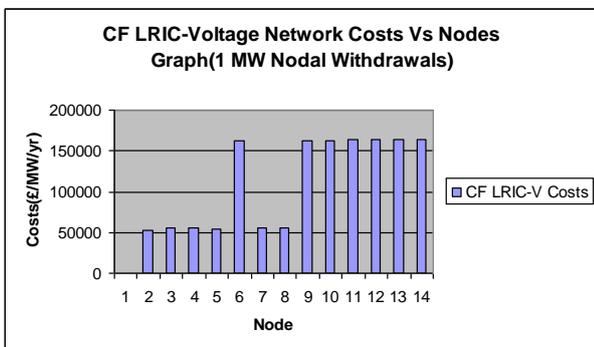


Fig. 9: CF LRIC-voltage network charges due to 1 MW withdrawal at each node

During 1 MW nodal withdrawals, the nodal voltage changes were relative smaller than in the MVar nodal withdrawals' case and, as such, the number of nodal lower voltage limits reached was few, hence, less comparable

nodal costs. The following number of nodal lower voltage limits has been reached, therefore, reinforcements indications were as follows:

- 1) During MW withdrawals at buses 2, 3, 4, 5, 7 and 8, reinforcements were triggered at bus 13.
- 2) MW withdrawals at buses 6, 9, 10, 11, 12, 13 and 14 triggered reinforcements at buses 5 and 13.

Given the above triggered reinforcements, buses 2, 3, 4, 5, 7 and 8 attract costs around the region of £52, 865.00 to £55, and 881.00 since they all triggered one reinforcement investment. On the other hand, the rest of the buses, excluding the slack bus, triggered two reinforcement investments, therefore, comparatively more costs ranging from £162, 645.00 to £163, and 955.00. However, the costs are relatively more during the 1 MVar withdrawals since up to three reinforcement investments were triggered.

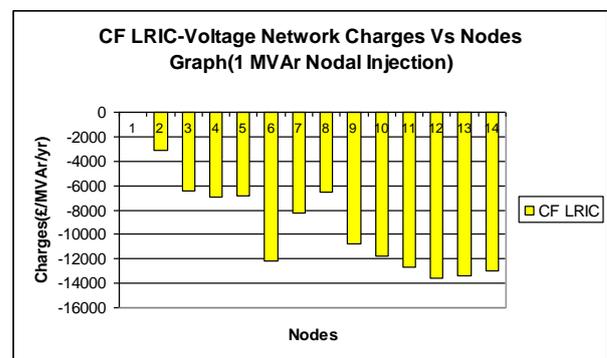


Fig. 10: CF LRIC-voltage network charges due to 1 MVar injection at each node

During nodal injections, there were not limits reached. It should be noted that the ranges of nodal voltage limits with contingency factors considered is less than that without contingency factors considered. This factor leads to more nodal credits for CF LRIC-voltage network charges than base LRIC-voltage network charges. It should also be noted that the nodal credits follow the same pattern as the case without considering the contingency factors but only increased credits, therefore bus 12 attracts the most credits while bus 2 the least.

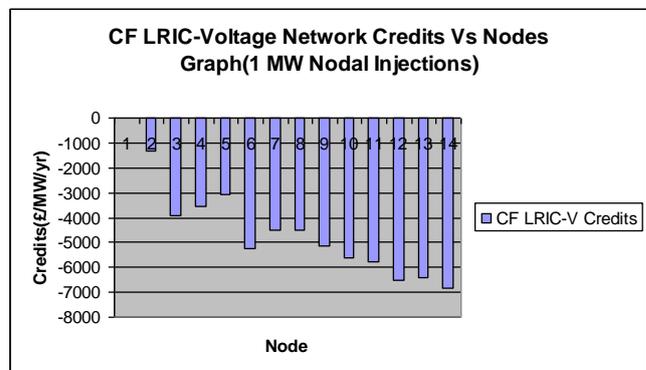


Fig. 11: CF LRIC-voltage network charges due to 1 MW injection at each node

It can be seen from Fig. 11 that the results follow the same pattern as those of Fig. 5, but, the credits sought in the former case are small than in the latter one since the

network resulting reactance ( $X$ ) is more than the corresponding resulting resistance ( $R$ ) and, hence, less network nodal voltage increments.

#### IV. CONCLUSIONS

This paper presents a novel long-run incremental cost (LRIC) pricing principle to price the cost of network reactive power compensation for keeping the system voltages within statutory limits when subjected to N-1 contingencies. This principle is based on the spare nodal voltage capacity of an existing network to reflect the impact to the network wide voltage profile and the cost of future network VAR compensation consequent upon a nodal injection/withdrawal, i.e. whether they accelerate or delay the need for future network compensation devices. The model is thus cost-reflective and able to provide forward-looking economic signals to influence network users' behavior in order to minimize the cost of future investment in VAR compensation. Most importantly, these principles integrate the MW and MVAR perturbations.

The separation of pricing the use of network for carrying reactive power (the use of circuits and transformers) and Generating reactive power (the use of VAR compensation Devices) also adds further clarity thus transparency to network users of their respective impact to the future network investment.

This study was carried-out on a 14-bus network. The major findings from the demonstrations are summarized as follows:

- 1) Both the Base and CF LRIC-V network charges increase as the nodal withdrawal/injection distances increase from the slack bus and the extent at which the buses are utilized.
- 2) the base LRIC-V network charges do not take into Account N-1 contingencies which are a statutory requirement for network operators to maintain security of supply, therefore, provide incorrect price signals.
- 3) The CF LRIC-V network charges consider N-1 contingencies, accounting for the additional cost brought to the network operator, therefore, provide more cost-reflective economic signals for network users to make informed decisions.
- 4) The CF LRIC-V network charges are more than base LRIC-V network charges since each network bus voltage Limit range (both the lower and higher limit margins are Reduced) used for determining the former is reduced to Accommodate the constraints of supporting N-1 Contingencies and, as such, each network bus headroom is Inherently reduced.

This paper demonstrated a very simplistic approach to determine the cost/benefit of LRIC-voltage network charges on a system subjected to N-1 contingencies (which is a statutory requirement for network operators) and, further, compared the charges when these contingencies are considered and when not considered. The charges with N-1 contingencies provide better economic signals to potential network users which, in turn, will help them to exercise an economic choice as to whether to invest in reactive power devices or pay the network operators for reactive power provision. Ultimately, this will guide towards an effective

and efficient usage of the network's reactive power resources.

Compared with the currently used power factor (pf) penalty, the proposed novel LRIC-voltage network charging principle is able to provide correct nodal forward-looking charges, incentivizing those network users who defer overall network investment in VAR compensation costs and, otherwise, penalize those who bring closer the network VAR compensation investment horizons. It should be noted that pf penalty approach only penalizes those network users who operate below the preset trigger threshold but fails to incentivize those that operate above the preset pf threshold. In addition, the pf penalty approach was used specifically to recover charges for generator operating costs, that is, ensuring that network losses are reduced. Furthermore, different network companies have different pf penalty trigger thresholds [42, 43, 44] and, for that reason, it can be concluded that there is no solid basis for determining such and, therefore, it is not cost reflective [45].

The next phase would be to price for the existing network compensation devices at the nodes where these exist and, ultimately, the reactive power planning (RPP) problem would be integrated with the LRIC-voltage network pricing approach, to price for the future and the aforementioned existing network VAR compensation assets as the most practical approach to employ. In this case, N-1 circuit contingencies should be considered.

#### V. APPENDIX

The used IEEE 14 bus network is described in detail in [46]. The loading and the generation conditions of this used network are shown below in TABLES, 3 and 4, respectively.

TABLE 3  
IEEE 14 NETWORK LOAD DATA

Bus	MW	MVAr
1	0	0
2	21.7	12.7
3	94.2	19
4	47.8	-3.9
5	7.6	1.6
6	11.2	7.5
7	0	0
8	0	0
9	29.5	16.6
10	9	5.8
11	3.5	1.8
12	6.1	1.6
13	13.5	5.8
14	14.9	5

TABLE 4  
 IEEE 14 GENERATOR DATA

Bus	Real Power(MW)	Max VAr(MVAr)	Min VAr(MVAr)	Voltage pu
2	40	50	-40	1.045
3	0	40	0	1.01
6	0	24	-6	1.07
8	0	24	-6	1.09

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