F-Factor Impact Analysis

DCP 313 Working Group

DCUSA Ltd

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Executive Summary

A qualitative assessment has been made of the impact changing an embedded generator F factor may have on customer Charge 1 values and NUF factors. If the F factor of a generator is defined based purely on technology type as suggested in DCP 313 option 2, then generators which were deemed not to contribute to network security and were assigned a zero F factor could be assigned a non-zero F factor. This would have a similar effect as if these generators were added as new generation into the maximum demand scenario model.

In general, adding a new generator may delay the year in which network branches could require reinforcement. Delaying the year of reinforcement would generally reduce customer Charge 1 values in both the LRIC and FCP methodologies.

The amount of any charge reduction would depend on the location of branches, whose reinforcement has been delayed, with respect to customers. For LRIC, this depends on the branches which a nodal demand 'uses', while for FCP it depends on the network group which the nodal demand is in.

In addition to the relative locations of nodal demands, branches and generators, the cost reduction will be influenced by the branch reinforcement cost and reinforcement year. Delaying reinforcement of a more expensive branch or a branch which requires reinforcement in 'early' years will have the greatest impact on costs.

It is possible that adding new generators will have no impact on customer charges. This happens in FCP if the new generators are not large enough to delay branch reinforcement or there are no branches which require reinforcement in the local network area. In LRIC, this happens if the branches with delayed reinforcement are not "used" by the customer.

New generation is more likely to reduce charge 1 values in a demand dominant network than in a generation dominant network.

Adding a new generator does not change the branches 'used' by a nodal demand when calculating NUFs. In demand dominant networks the new generator may decrease the maximum contingency flow on those branches which a nodal demand uses, which may generally decrease NUFs. There is a case, however, where the maximum contingency flow on a demand dominant branch may be increased by the addition of a new generator, which would increase NUFs.

In a generation dominant network adding a new generator may increase the maximum contingency flow on branches used by a nodal demand, which may increase NUFs. The base flow on branches used by the nodal demand, however, may either increase or decrease depending on branch/load/generator locations which would either decrease or increase NUF values correspondingly.

When a new generator alters the maximum contingency flow of a branch the magnitude by which the NUF factor is altered would depend on the size of the change in flow in proportion to the branch rating. Whether a branch NUF allocation increases or decreases in a generation dominated asset would further depend on the magnitude of this change combined with the magnitude of change in 'base flow' compared to 'base flow load'. If the change in flow values is small compared to the branch rating (and existing base flow) then the magnitude change to NUF values will also be small.

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1   Introduction

This assessment has been undertaken in response to a request from the DCP 313 Working Group to provide a generic description of the impact on the charges for a given generator of changing from having a zero F factor assigned to having a non-zero F factor assigned and the likely impact on the charges for other customers connected to the local network. A qualitative assessment has been undertaken on both Long Run Incremental Cost (LRIC) and Forward Cost Pricing (FCP) Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) charging methodologies as well as Network Use Factors (NUF). When considering customer charges the impact has been limited to the customers 'charge 1' value, which is the output of the power flow analysis process and the input to 'Workstream B' calculations.

1.1   What is F Factor

The legal text in schedules 17 and 18 requires Distribution Network Operators (DNOs) to determine an F factor for each EDCM embedded generator based on the criteria set down in Engineering Recommendation P2/6 – 'Security of Supply' (ER P2/6) and Engineering Technical Report 130 – 'Application Guide for Assessing the Capacity of Networks Containing Distributed Generation' (ETR130). The F factor is determined based on generation technology type and a site-specific assessment of the contribution to network security of each EDCM embedded generator, taking into account availability and the operating regime, alongside intermittency.

EDCM embedded generators are deemed to be eligible to receive charge one credits (unit rate credits applicable in the DNO's peak 'super-red' period, calculated based on a power flow analysis of the DNO's network) if they have a non-zero F factor, and are deemed not eligible to receive charge one credits if they have a zero F factor.

1.2   What is DCP 313

DCP 313, is seeking to amend the EDCM to improve transparency in the way in which F factors are assigned to generators for the power flow modelling, and then the criteria by which a given generator will be eligible for credits is determined, which is an input to the EDCM model itself. The reason for the change is that the requirements of P2/6 when setting the F factor rely on data which is only available to the DNO, and there is a concern among generators that different DNOs may be applying different interpretations of P2/6 when determining the F factor to use.

One of the solutions (Option 2) the Working Group is looking at would involve replacing the use of F factors in the power flow modelling with an equivalent factor which would be determined entirely based on the technology type of the generator in question. This will inevitably lead to some generators which currently have a zero F factor changing to have a non-zero F factor and vice versa.

2   LRIC Methodology

The LRIC model calculates a pair of **branch incremental costs**, one for the maximum demand scenario (peak, charge 1) and another for the minimum demand scenario (off-peak, charge 2), for each network branch for an increment of demand or generation in each network node. It uses AC power flow analysis, which calculates the time needed (**years to reinforcement**) before elements of the network require reinforcement, and subsequently the net present value (NPV) of the future costs of reinforcement. The branch incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added. The **nodal charges** are then calculated by summating all the branch incremental costs. Only branches that experience a change greater than a small kVA and percentage of base power flow thresholds, when a given nodal demand is increased by a small amount, are used in the calculation of that nodal demand's charges.

The year of reinforcement for each branch is determined by first performing contingency analysis on the network. Appropriate contingencies, single or double outages in accordance with ER P2/6, are simulated. The flow in all branches after each contingency, the post-contingency flow, is recorded. The year of branch reinforcement is determined by the contingency which creates the largest post-contingent flow in each branch.

The largest post-contingent flow in each branch is compared to its rating and the year in which reinforcement is required determined by applying a 1% per annum demand growth rate.

It should be pointed out that each branch incremental cost is considered in just one out of the two charge periods (peak or off-peak but not both) based on the scenario that drives the maximum absolute value of branch incremental cost.

Branch incremental cost for the minimum demand scenario (off-peak, charge 2) plays an important role in the EDCM "power flow" model. In LRIC if charge 2 is found to be grater than charge 1, charge 1 will not be considered in the nodal charge calculation (equivalent to assigning zero to charge 1 for this branch).

For the maximum demand scenario, the generation export is set to the maximum export capacity (MEC) multiplied by a F Factor. The F factor is set to zero unless it is deemed to contribute to network security in accordance with P2/6. The generation export used for the minimum demand scenario is set to the MEC, factored to reflect coincidence with other EDCM generators within the GSP network group.

If the F factor of a generator is defined based purely on technology type as suggested in DCP 313 option 2, then generators which were deemed not to contribute to network security and were assigned a zero F factor could be assigned a non-zero F factor. This would have a similar effect as if these generators were added as new generation into the maximum demand scenario model. The change of a generator F factor from a zero to non-zero value will have no impact to the branch incremental costs calculated under minimum demand scenario.

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2.1 Impact on Nodal Charge 1 in Demand Dominant Networks

For a demand dominated network, the headroom of network branches available for load growth under the maximum demand scenario is usually less than the headroom available under the minimum demand scenario. Branch reinforcement will always be driven by the maximum demand scenario, and hence the corresponding branch incremental cost (charge 1) tends to be higher than under the minimum demand scenario. In addition, a change of F Factor will not affect the branch incremental cost calculated under minimum demand scenario and hence it is logical to exclude the minimum demand scenario when considering the impact on nodal charge 1 in a demand dominant network.

The formulae to calculate branch incremental cost due to an increment at a node and nodal charges are provided in Annex 1 of the LRIC Methodology Document[1]. It can be deduced from the formulae that the most important element affected by the addition of new generation which eventually impact the nodal charges for each customer is the years to reinforcement.

2.1.1 The impact of new generation location on network reinforcement time

An example Grid Supply Point (GSP) has been considered which incorporates two 132kV/EHV (Bulk Supply Points or BSPs) substations connected on a 132kV ring, each with a single EHV/HV (Primary or PRY) substation connected by double circuit EHV lines. The impact on the time to reinforcement has then been considered for a generator connected to the GSP, to 132kV circuits, to the BSPs, to EHV circuits or to each of the PRYs. In all cases except for that labelled E* the new generation connected has been assumed to not be sufficiently large to reverse power flows in any assets.

Considering the potential new generation locations shown in Figure 2-2, , Table 2-1 indicates the network branches which may see a change in reinforcement year due to new generation. In general, the reinforcement year of these network branches either remains unchanged or is delayed in a demand dominated network, depending on the location of the new generator with respect to the network branches. The network may see a delay in reinforcement if the new generator causes a reduction in maximum post contingency flow through the network branch. A reduction in intact flow due to a new generator does not guarantee a delay in network reinforcement. Note that because flow on the branch LGSP3 in the demand dominated network is from BSP2 to BSP1, connecting a new generator at location C will not reduce the amount of power that needs to flow through LGSP3. Connecting a new generator at location D, however, will reduce the amount of power that needs to flow through LGSP3.

For the network branches which experience a delay in network reinforcement, the magnitude of delay will depend on the nodal sensitivity factor[2] of the new generation with respect to the branch under post contingency network configuration. The generator which is connected at a network node with a larger nodal sensitivity factor with respect to the network branch, which results in a greater reduction in post contingency flow, will result in a longer delay in network reinforcement.

However, it should be noted that if it is a very large new generator, which results in a change of power flow direction, and the new power flow magnitude is greater than the magnitude of flow before change, the time of reinforcement calculated for the network branch will decrease (accelerate).

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[1] Schedule 18 – EHV Charging Methodology (LRIC Model), Version 10.3
[2] Nodal sensitivity factor of a branch with respect to a generator node can be defined as the ratio of MVA power flow change on the branch to a MVA injection to the node.

Figure 2-1: Example of Demand Dominated Network
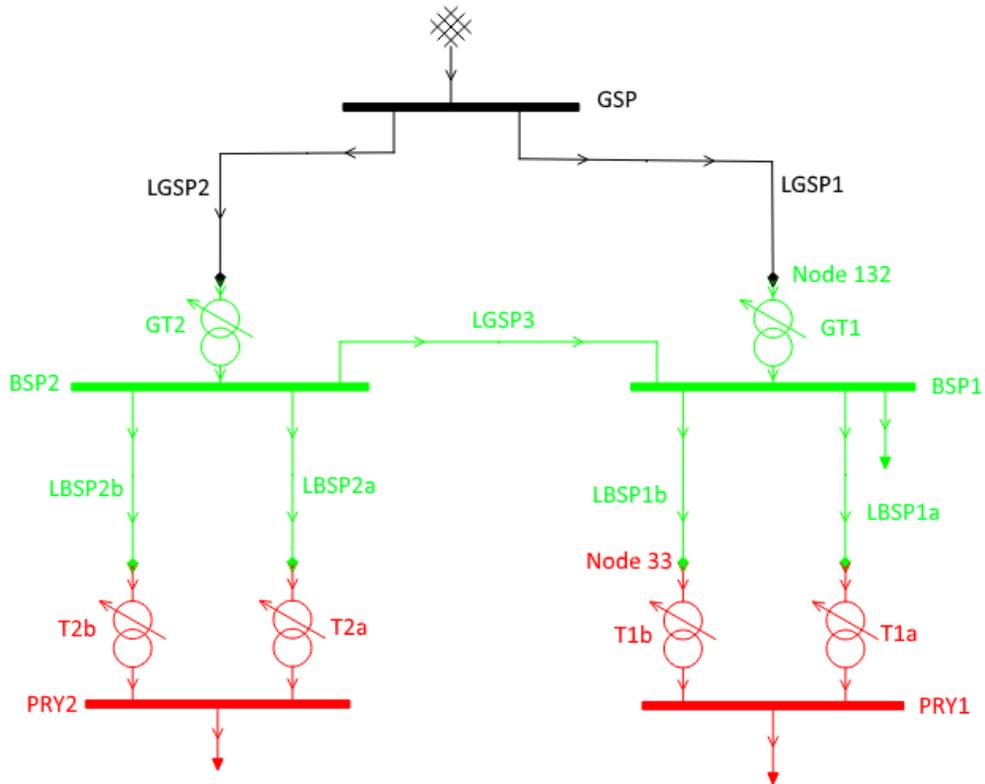
Figure 2-2 Example of Demand Dominated Network with potential new generator locations shown
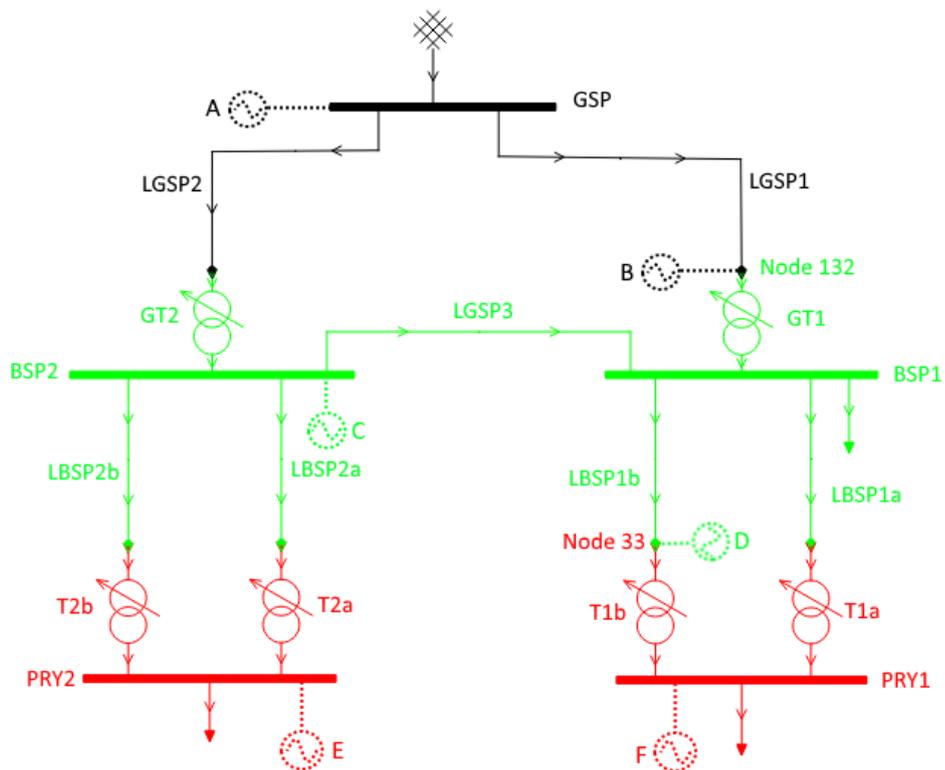
Figure 2-3: Example of Generation Dominated Network
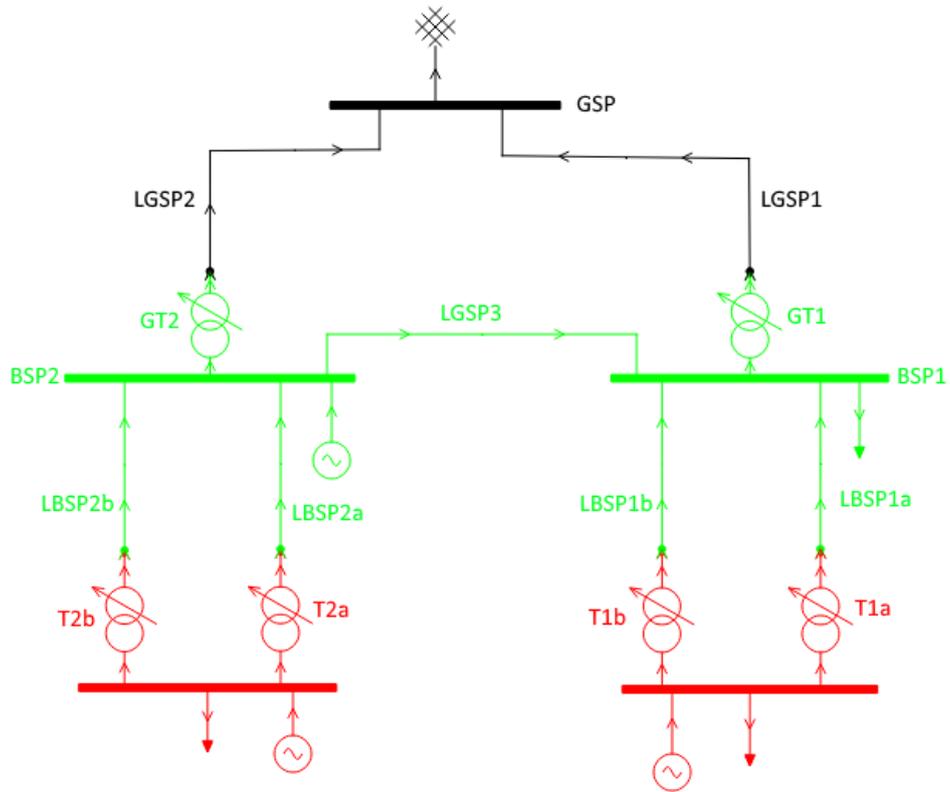
Table 2-1: Changes of reinforcement time of each network branches to different generator location

Branch/ Gen	LGSP1	GT1	LGSP2	GT2	LGSP3	LBSP1a	T1a	LBSP1b	T1b	LBSP2a	T2a	LBSP2b	T2b
A													
B	Delay												
C	Delay	Delay	Delay	Delay									
D	Delay	Delay	Delay	Delay				Delay					
E	Delay	Delay	Delay	Delay						Delay	Delay	Delay	Delay
F	Delay	Delay	Delay	Delay	Delay	Delay	Delay	Delay	Delay				
F*	Delay	Delay	Delay	Delay		Accelerate	Accelerate	Accelerate	Accelerate				

☐	No Change
🟩	Delay
🟥	Accelerate

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2.1.2   The impact of generation location on branch incremental cost and nodal charge

Based on Table 2-1 and Figure 2-2, in which the impact of the generation location on network reinforcement time is summarised the impacts on branch incremental cost can be deduced. By summating the branch incremental costs the impact on the nodal charge can be assessed.. The potential impact on nodal charges is described below and in Table 2-2.

- **A new generator at location A** would not reduce the maximum flow on any network branches considered in EDCM analysis so this would not impact the charges for any customers.

- **A new generator at location B** may reduce flow in branch LGSP1 and delay a potential reinforcement to this branch. Every nodal demand location can be considered to "use" this branch, so nodal demand may be reduced for all customers.

- **A new generator at location C** may reduce flow and delay reinforcement on the branches LGSP1, GT1, LGSP2 and GT2. Every nodal demand location can be considered to "use" these branches, so nodal demand may be reduced for all customers.

- **A new generator at location D** may reduce flow and delay reinforcement on the branches LGSP1, GT1, LGSP2, GT2, LGSP3 and LBSP1b. Every nodal demand location can be considered to "use" some or all of these branches (while a demand at node PRY2 would not "use" branch LBSP1b, it would "use" the other branches). Nodal demand may be reduced for all customers therefore.

- **A new generator at location E** may reduce flow and delay reinforcement on the branches LGSP1, GT1, LGSP2, GT2, LGSP3, LBSP2a, T2a, LBSP2b and T2b. Every nodal demand location can be considered to "use" some or all of these branches (while a demand at node PRY1 would not "use" branches LBSP2a, T2a, LBSP2b and T2b, it would "use" the other branches). Nodal demand may be reduced for all customers therefore.

- **A new generator at location F** may reduce flow and delay reinforcement on the branches LGSP1, GT1, LGSP2, GT2, LGSP3, LBSP1a, T1a, LBSP1b and T1b. Every nodal demand location can be considered to "use" some or all of these branches (while a demand at node PRY2 would not "use" branches LBSP1a, T1a, LBSP1b and T1b, it would "use" the other branches). Nodal demand may be reduced for all customers therefore.

  If the size of generation connected at PRY1 was very large in comparison to the existing demand flow it may reverse the direction of flow on branches LBSP1a, T1a, LBSP1b and T1b. If the magnitude of the reversed flow on these branches was greater than the existing demand flow before the generator is connected, the calculated years to reinforcement for those branches would be reduced. In that case it is possible that nodal demands at PRY1 may have an increased charge 1 due to the generator connection.

  In the specific case which this report is addressing, a generator changing from zero to non-zero F-factor, such a generator will already have output in the minimum demand scenario. It is likely that these branches would have a larger charge 2 than charge 1 value both before and after the F-factor change. Therefore, as discussed in section 2, charge 1 would actually be set to zero in both circumstances (since charge 2 > charge 1) and hence there will be no impact on the charge 1 value for these branches due to the generator F-factor change.

Table 2-2 Potential impact of new generator in the power flow model on charge 1 by Customer node

Generator Location	Customer Charges				
	GSP	BSP1	BSP2	Pry1	Pry2
A					
B		🟩	🟩	🟩	🟩
C		🟩	🟩	🟩	🟩
D		🟩	🟩	🟩	🟩
E		🟩	🟩	🟩	🟩
F		🟩	🟩	🟩	🟩

⬜	No Change
🟩	Delay
🟥	Accelerate

In general, branch incremental cost reduces when the years to reinforcement is increased. This is the case for all generator locations except A and F*. The impact is wider and the magnitude of nodal charge reduction is higher if the new generator is connected in a lower level network group and/or if the demand in question is connected in a lower network group level. For example, a customer connected at Pry1 is likely to see a greater nodal charge reduction with a new generation connected at location F as compared to a new generation (assuming same MEC) at the locations C or D. Similarly a customer connected at BSP2 is likely to see a greater nodal charge reduction with a new generation connected at location C and Primary level as compared to a new generation connected at GSP level.

Apart from the generator locations, it should be noted that the magnitude of branch incremental cost reduction also depends on the cost to reinforce the branch and the years to reinforcement of the branch. If it is an expensive long circuit (e.g. a 20 km overhead line), the reduction of branch incremental cost is high. Similarly, if the years to reinforcement of the branch was small, the impact on branch incremental cost is also high. For example the magnitude of reduction in incremental cost for a branch which has a reinforcement time delayed from year 1 to year 2 is a lot higher (varies exponentially) than a branch which has a reinforcement time delayed from year 20 to year 21.

Also, a reduction in charge 1 incremental cost for a branch can potentially result in charge 2 becoming dominant (reinforcement of the branch is now driven by minimum demand scenario) and result in charge 1 not being used in the calculation of nodal charges.

2.2   Impact on Nodal Charge 1 in Generation Dominant Network

In a generation dominant network, the majority of the network branch reinforcements are likely to be driven by the minimum demand scenario. As branch incremental cost is only considered in one out of the two charge periods (maximum or minimum demand scenario), it is likely that nodal charge 1 for customers connected in the network is smaller than charge 2. As discussed previously if charge 2 is greater than charge 1 then charge 1 is set to zero.

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In a network area which is generation dominant a scenario could exist where reinforcement of all branches is driven by the minimum demand scenario. In this case charge 1 would be zero for all customers which only use branches in that network area.

The addition of a new generator in a generation dominated network will either reduce charge 1 further, or in the case where charge 1 was already zero in value have no impact.

2.3   Summary

In summary, adding new generation to a network may reduce network group charge 1 values. A generator which reduces the flow on any given branch has the potential to decrease the charge 1 value for any branch which "uses" that branch. For a given nodal demand the magnitude of charge 1 reduction is likely to be greater the closer electrically the new generation is connected to it.

If a generator reduces the year to reinforcement of a branch, the branch incremental cost and therefore the charge 1 value of a node which uses the branch will reduce. The reduction will be greater for branches which the original year to reinforcement is shorter.

Changing a generator's F-factor from zero to a non-zero value is more likely to reduce charge 1 values in a demand dominant network than in a generation dominant network. In a generation dominant network charge 1 may already be low or zero.

3   FCP Methodology

In FCP, charge 1, is calculated for each network group. Groups are categorised into three levels, the assets associated with each level are as follows:

Level 1 (GSP Group): EHV branches connecting GSPs to BSPs and EHV branches connecting 132 kV busbars in the same GSP group. Black components in Figure 3-1.

Level 2 (BSP Group): BSP transformers and outgoing network group branches. Green components in Figure 3-1.

Level 3 (Primary Group): Primary transformers only. Red components in Figure 3-1.

An incremental charge is calculated for each asset that requires reinforcement during the 10-year planning horizon. If the year in which reinforcement is required is later, the charge for that asset reduces.

Similar to LRIC, the requirement to reinforce branches is determined by performing contingency analysis on the network. Appropriate contingencies, single or double outages in accordance with ER P2/6, are simulated. The flow in all branches after each contingency, the post-contingency flow, is then compared to the branch rating. Requirement for branch reinforcement is driven by the contingency which creates the largest post-contingent flow in each branch.

The year to reinforcement of each branch is determined by performing the contingency analysis against the predicted network load in the 10-year planning horizon. The earliest year in which a branches post-contingent flow exceeds branch rating is taken as the year in which reinforcement is required.

The charge 1 value for each group consists of, the sum of the incremental charges for all the assets in that group which need reinforcing during the 10-year planning horizon, plus the charge 1 value of all the higher level groups under which it is a child.

In the network shown in Figure 3-1 the charge for group GSP 1 (a level 1 group) will contain costs associated with asset reinforcements in group GSP 1 only. The charge for group BSP 1 (a level 2 group) will contain costs associated with asset reinforcements in group BSP 1 and group GSP 1, while the charge for group Primary 1 (a level 3 group) will contain costs associated with asset reinforcements in group Primary 1, group BSP 1 and group GSP 1.

Considering customers, customer C1 is connected at a level 1 group and will be assigned charges related to reinforcement costs to network assets in group GSP 1 (black zone). Customer C2 is connected at a level 2 group and will be assigned charges related to reinforcement costs to network assets in group BSP 1 (green zone) **in addition** to charges related to reinforcement costs in its parent level 1 group (i.e. group GSP 1). Customer 3 and customer 4 are connected at level 3 groups and will be assigned charges related to reinforcement cost of the primary transformers supplying their separate primary network groups (red zones) **in addition** to charges related to their parent level 2 and grandparent level 1 groups.

If a generator is defined an F factor based purely on technology type, then generators which may have been assigned zero F factor could be assigned a non-zero F factor. This would have the effect of introducing a new generator in the power flow model. If new generation is introduced in the model, it can be appreciated that the year in which an asset may be overloaded, due to load growth, may be delayed, possibly even beyond the 10-year horizon.

Figure 3-1 Network groups
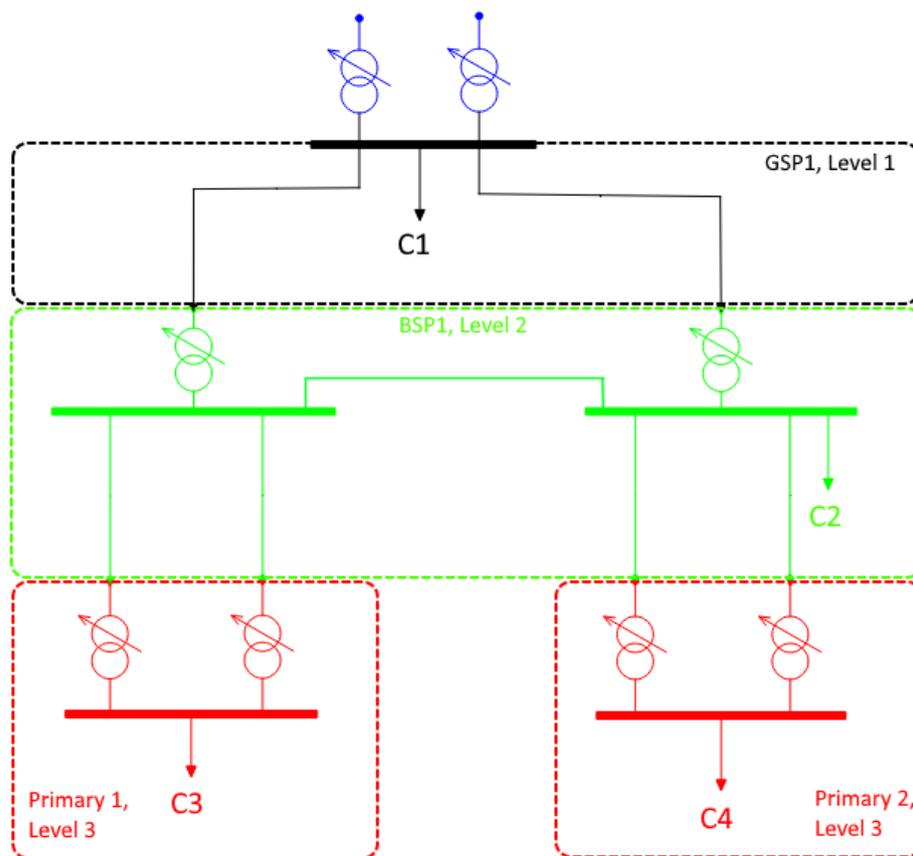
3.1   Impact on Charge 1 in Demand Dominant Networks

The impact of additional generation on a power flow model group's potential charge depends on two factors:

- Potential delay in asset reinforcement year.
- Potential reduction in network group charge 1.

Figure 3-2 hypothetical demand dominant network
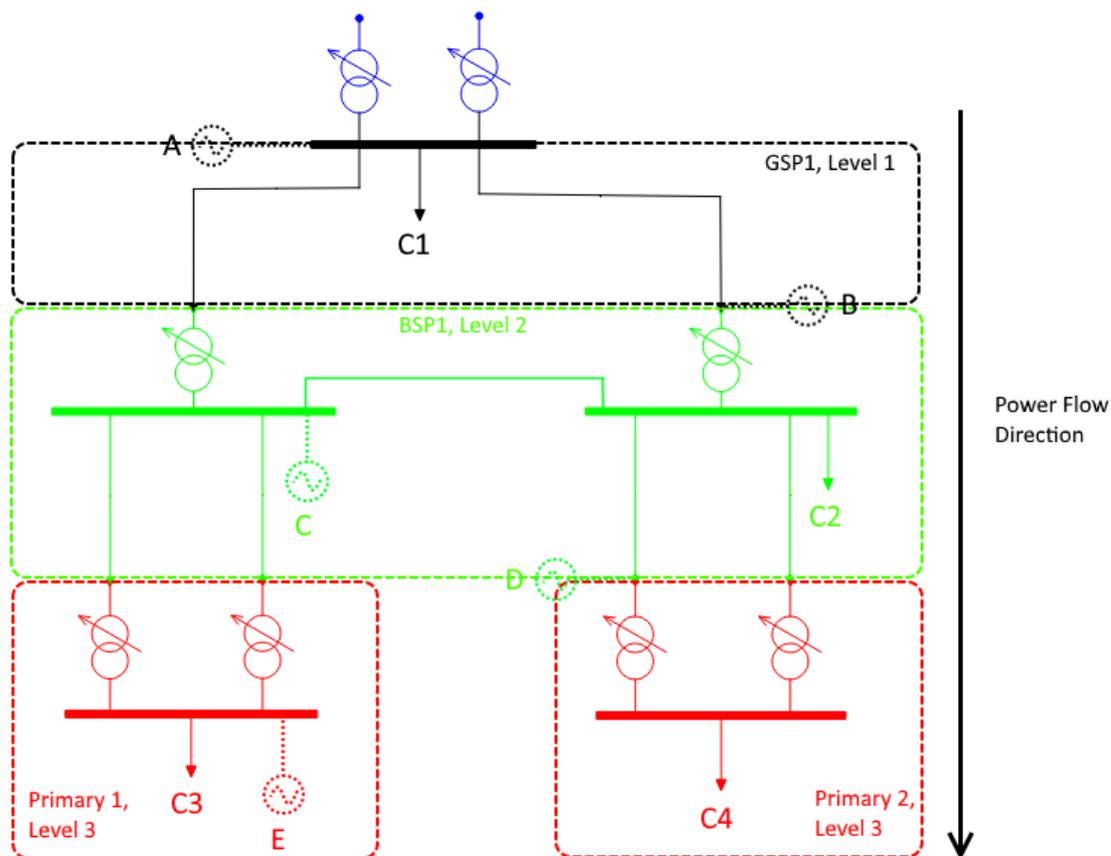
3.1.1   Potential delay in asset reinforcement year

Firstly, the generators location in the network impacts which assets would see a reduced flow due to network demand. Reducing branch flow due to demand would potentially delay the year in which a branch would require reinforcement due to load growth.

Considering the potential new generator locations shown in Figure 3-2, Table 3-1 indicates the assets (by group) which may see a delayed reinforcement year due to new generation. It could be appreciated that generators which are connected at a particular level are more likely to mitigate reinforcement of assets in that level. For example the reduction of demand flow, comparted to asset rating, due to generation connected at location E is likely to be greater for branches in group Primary 1 rather than group GSP 1. The generation at location E may however still reduce flow in the group GSP 1 assets.

Table 3-1 Potential delay in asset reinforcement in network levels by generation location

Generator Location	Network group			
	GSP 1, Level 1	BSP 1, Level 2	Primary 1, Level 3	Primary 2, Level 3
A				
B	Delay			
C	Delay	Delay		
D	Delay	Delay		
E	Delay	Delay	Delay	

□ No Change

■ Delay

■ Accelerate

3.1.2   Potential reduction in network group charge 1

A network group (and therefore customer) location in relation to a branch whose reinforcement year is delayed impacts whether or not that group charge 1 value may be reduced. Table 3-2 summarises this effect. Since the charge 1 value for a level 3 group includes the reinforcement costs of the parent and grandparent networks under which it is connected, all the generator locations in Figure 3-2, except location A, have the potential to reduce the charge 1 value of every group within the same GSP group. Although no generator may reduce the asset flows in group Primary 2, all generators may reduce flows in the groups GSP 1 or BSP 1 and therefore would impact the charge 1 value of the group. This is described in more detail below:

- **A new generator at location A** may reduce flow on the GSP transformer supplying the network group. Reinforcement of GSP transformers is not considered in EDCM analysis so this would not impact the charges for any customers.

- **A new generator at location B** may reduce flow in the right hand branch supplying the BSP and delay a potential reinforcement to this branch. Delaying the reinforcement of a GSP branch would reduce the charges assigned to customers connected in that GSP group, its child BSP group and its grandchild primary groups, in this example customers in locations C1, C2, C3 and C4. Generators at locations C, D and E may also reduce flow in the 132 kV branches hence also impacting the charge 1 values of these customers.

- **A new generator at location C** may also reduce flow on the BSP transformers supplying the BSP group and delay a potential transformer reinforcement. Delaying the reinforcement of a BSP transformer would reduce the charges assigned to customers connected in that BSP group and its child primary groups, in this example customers in locations C2, C3 and C4. Generators at locations D and E may also reduce flows on the BSP transformers hence also impacting the charge 1 values of customer C2, C3 and C4.

- **A new generator at location D** may also reduce flow on the BSP branch supplying the primary transformer and delay a potential branch reinforcement. Delaying the reinforcement of a BSP branch would reduce the charges assigned to customers connected in that BSP group and its child primary groups. in this example customers in locations C2, C3 and C4. A generator at location E may also reduce flow on the EHV branches supplying the primary transformer it is supplied by, hence also impacting the charge 1 values of customer C2, C3 and C4.

- **A new generator at location E** may also reduce flow on the primary transformers supplying the primary group and delay a potential transformer reinforcement. Delaying the reinforcement of a primary transformer would reduce the charges assigned to customers connected in that primary group. In this example customers in location C3.

Table 3-2 Potential impact of new generator in the power flow model on charge 1 by network group

Generator Location	Network group			
	GSP 1 (Level1, GSP group 1)	BSP 1 (Level 2, GSP group 1, BSP group 1)	Primary 1 (Level 3, GSP group 1, BSP group 1, Primary group 1)	Primary 2 (Level 3, GSP group 1, BSP group 1, Primary group 2)
A				
B	Decrease	Decrease	Decrease	Decrease
C	Decrease	Decrease	Decrease	Decrease
D	Decrease	Decrease	Decrease	Decrease
E	Decrease	Decrease	Decrease	Decrease

(white)	No Change
(green)	Decrease
(red)	Increase

It should be noted that the discussion here refers to potential charge changes. The impact of a new generator on branch flows would be dependent on location, network configuration and the location of existing generator and demand connections. It is entirely possible that a new generator would have no impact on customer charges. For example, if there were no reinforcements identified in a network group before the new generator is added then there would be no reinforcement to delay, or if the new generation is not sufficient to delay a reinforcement then the costs would also remain unchanged.

3.2 Impact on charge 1 in generation dominant networks

The impact of modelling additional generation in a generation dominant network would have a similar high level effect on FCP charge 1 as described in section 3.1 for a demand dominant network. However, the probability of reducing FCP charge 1 in a generation dominant network is likely to be much lower.

It is anticipated that the number of network reinforcements required in a generation dominant network due to load increase over the 10-year load forecast period would be much less, therefore associated cost reductions due to delaying reinforcements would be less. There would have to be a large step-change increase in demand flow in the 10-year demand forecast in order to overload a generation dominant asset due to demand flow.

Should there be a very large decrease in demand, it is possible that an asset may be overloaded due to generation flow, resulting in an increase in the FCP charge 1 figure, however this possibility is considered unlikely.

3.3 Summary

In summary, adding new generation to a network may reduce network group charge 1 values. A generator connected at any level within a network group (except for generator directly connected to a GSP substation) has the potential to decrease charge 1 values for all sub-group levels (1 to 3) within that GSP network group. Generators connected at higher voltage levels (e.g. Level 1) may have a greater impact on group charges than generators connected at lower levels (e.g. Level 3). If no network asset overloads exist in the group in the 10-year planning horizon before the new generation is included then the generator will have no impact on group charge 1 values. Similarly, if the new generation included is not large enough to delay an identified asset overload there will be no impact on charge 1 values.

New generation is more likely to reduce charge 1 values in a demand dominant network than in a generation dominant network.

4 NUF Methodology

A high-level overview of the NUF calculation for a particular nodal demand is as follows:

Step 1 The network branches which a given nodal demand uses are determined.

Step 2 The 'MW usage' of each branch by the nodal demand is calculated.

Step 3 The 'total MW usage' of each branch by all network nodal demands is identified.

Step 4 The nodal demands proportionate usage of the branches it uses are determined to give an allocation (£/annum).

Step 5 The (£/annum) value for each branch that the nodal demand uses at each voltage level are summated. The voltage levels are '132 kV', '132 kV/EHV', 'EHV', 'EHV/HV' and '132 kV/HV'. At each level this summated value is then divided by the kW demand at the node to give a (£/kW/annum) value for each voltage level.

Step 6 The process of steps 1 to step 5 will have been carried out for each CDCM demand node in the network to calculate a (£/kW/annum) figure at each voltage level for each CDCM nodal demand. From these values the average CDCM (£/kW/annum) figure is calculated for each voltage level.

Step 7 The NUF for the EDCM nodal demand is calculated by dividing the (£/kW/annum) value for each voltage level by the corresponding average CDCM (£/kW/annum).

A variation in generation F factor would impact Step 4 of the NUF calculation, the formula for the (£/annum) calculation for a demand dominated branch is:

$$Alloc\ (£/year) = \left(\frac{[MW usage]}{[Total\ MW\ usage]} \right) * \left(\frac{abs\ [Max\ contingency\ flow]}{[Rating]} \right) * AMEAV$$

For a generation dominated branch the formula is:

$$Alloc\ (£/year) = \left(\frac{[MW usage]}{[Total\ MW\ usage]} \right) * \left(\frac{abs\ [Max\ contingency\ flow]}{[Rating]} \right) * \left(\frac{abs\ [Base\ flow\ load]}{[Base\ flow]} \right) * AMEAV$$

A network asset is considered to be generation dominant based on the following equation, which is also illustrated in Figure 4-1.

IF: 2 x abs(base flow load) ≤ abs(base flow – base flow load) THEN: asset is generation dominant

Figure 4-1 Demand / Generation dominant asset illustration
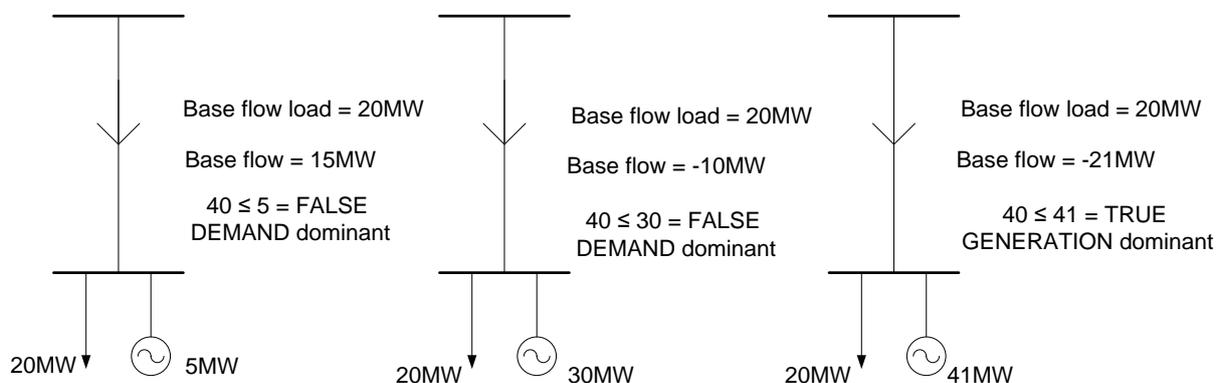
The "Base flow" in an asset, is the power flow in the asset due to network demand and generation under the system intact (N-0) condition before any contingencies are considered.

The "Base flow load" in an asset, is the power flow in the asset due to network demand only, with all embedded generators switched off, under the system intact (N-0) condition before any contingencies are considered.

The "Maximum contingency flow" in an asset, is the maximum power flow in the asset, due to network demand and generation, across all simulated network contingencies/outages.

Adding a new generator will not alter the branches which a nodal demand is deemed to use, however it can be appreciated that adding additional generation to the model would affect the "Max contingency flow" and "Base flow" of those assets.

When a new generator alters the maximum contingency flow of a branch the amount by which the NUF factor is altered would depend on the size of the change in flow in proportion to the branch rating. For example a 2 MVA generator connected to the end of a radial 50 MVA rated branch would have a much smaller impact on NUF factors than a 10 MVA generator connected to the end of a radial 15 MVA rated branch.

Modelling additional generation may also have a corresponding impact on calculated CDCM (£/kW/annum) values, however, when averaged across the entire network the impact on the average CDCM values would likely be diluted when compared to the impact on a particular EDCM nodes allocation.

4.1   Impact on demand dominant network

For a demand dominant branch the term (abs[Max contingency flow]/Rating) in the allocation equation is the term for which the result could be altered.

Where a new generation impacts the flows on a branch "used" by a nodal demand, it is likely that the "maximum contingency flow" would be reduced, reducing the NUF allocation for that asset to the customers NUF.

It is possible however, to imagine a case where adding a new generation may increase the maximum contingency flow. For example, if a primary group contains more generation than load and is exporting generation to the wider network, even if it is not generation dominant, (e.g. 2nd example in Figure 4-1) adding additional generation in that primary group may increase the maximum contingent flow across the circuits which are exporting the generation.

Thus it is seen that adding a new generation to a network, may either increase or decrease a nodal demands NUF at each voltage level dependant on the relative network locations and existing demand and generation flows in the network.

4.1.1   Impact on specific example network

Considering the demand dominant network shown in Figure 4-2, the impact of adding an additional 3 MW generator illustrated in Table 4-2.

Adding a new generator at location A would not impact the maximum contingency flow on branches.

A new generator at location B may reduce the maximum contingency flow on the branch 132kV-Cct2.

A new generator at location C would reduce the maximum contingency flow in the circuits 132kV-Cct1 and 132kV-Cct2 and the transformers 132kV/EHV-T1 and 132kV/EHV-T2. It is not considered

that the generator at this location would reduce maximum contingency flow on the EHV branches though, as the maximum contingency flow would be when the branch 132kV-Cct2 is outaged.

Note that the direction of flow in branch EHV-Cct1 is as indicated in Figure 4-2, during both intact network conditions and during maximum contingency flow conditions. For this branch the maximum contingency flow is when transformer 132kV/EHV-T2 is outaged. Consequently, a generator at location D will be considered to effect flow in the branch EHV-Cct1 but not a generator at location C.

A new generator at location D would reduce the maximum contingency flow in the circuits 132kV-Cct1 and 132kV-Cct2 and the transformers 132kV/EHV-T1 and 132kV/EHV-T2 long with the EHV circuits supplying demand C4, EHV-Cct1, EHV-Cct4 and EHC-Cct5.

A new generator at location E would reduce the maximum contingency flow in the circuits 132kV-Cct1 and 132kV-Cct2 and the transformers 132kV/EHV-T1 and 132kV/EHV-T2 long with the EHV circuits supplying demand C3, EHV-Cct1, EHV-Cct2 and EHC-Cct3.

If a nodal demand customer is considered to use branches which have a reduced maximum contingency flow then the NUF for those customers would reduce. The branch levels used by each of the customers are outlined in Table 4-1. It is seen that for this specific network that the NUF for customers C2, C3 and C4 would reduce.

Figure 4-2 NUF Demand dominant network example
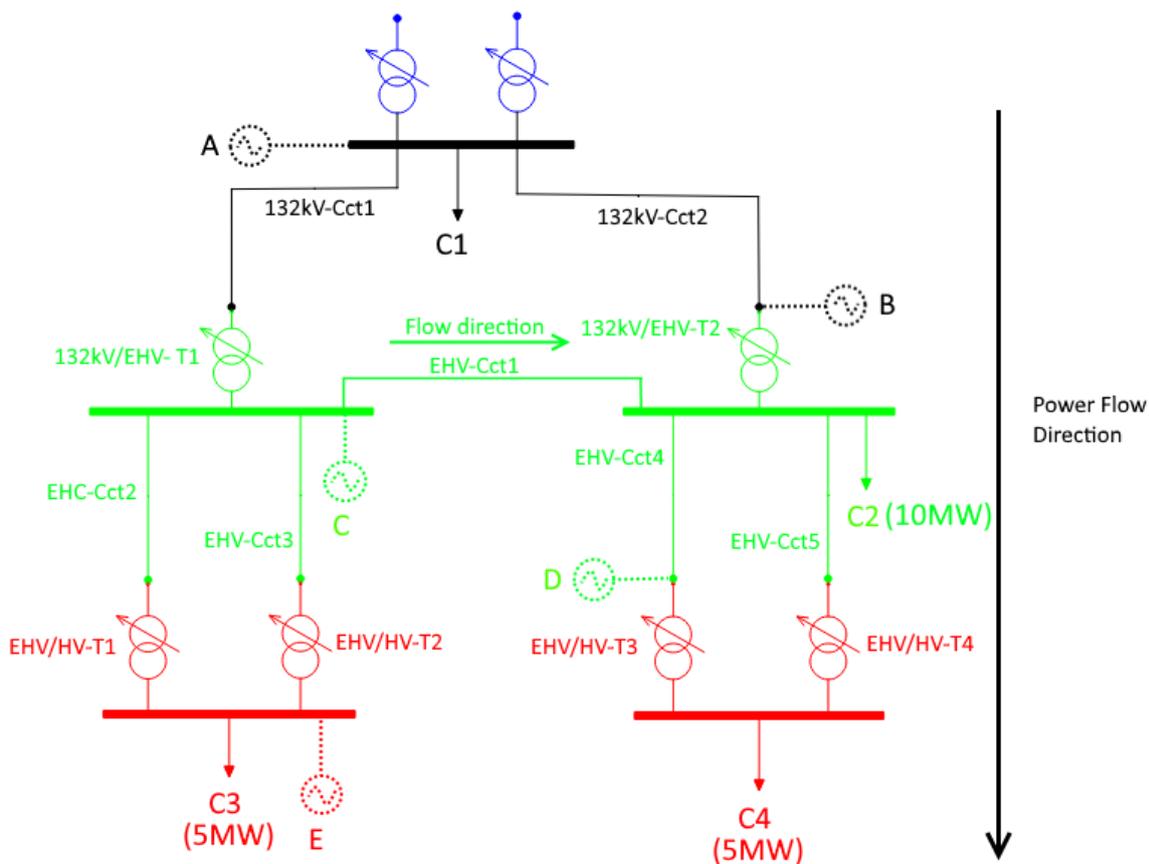
Table 4-1 Branches used by hypothetical customers by voltage level

Customer	Voltage level				
	132kV	132kV/EHV	EHV	EHV/HV	132kV/HV
C1					
C2	Used	Used	Used		
C3	Used	Used	Used	Used	
C4	Used	Used	Used	Used	

(white)	Not used
(green)	Used

Table 4-2 Potential impact maximum contingency flow of branches by voltage level

Generator location	Voltage level				
	132kV	132kV/EHV	EHV	EHV/HV	132kV/HV
A					
B	Decrease				
C	Decrease	Decrease			
D	Decrease	Decrease	Decrease		
E	Decrease	Decrease	Decrease		

(white)	No Change
(green)	Decrease
(red)	Increase

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4.2   Impact on generation dominant network

There are two items which may impact a nodal demands NUFs after the addition of a new generator to the model in a generation dominant network.

- Does the new generation change the maximum contingency flow of the branches which the nodal demand uses *(abs[Max contingency flow]/Rating)*.

- Does the new generation change the base flow on branches which the nodal demand uses *(abs[Base flow load]/base flow)*.

Where a new generation impacts the flows on a generation dominant branch "used" by a nodal demand, since the branch is exporting generation to higher voltage levels, it is likely that the "maximum contingency flow" would be increased as there is more generation to export, increasing the NUF allocation for that asset. It is also likely that the new generation would increase "base flow" on the asset as the amount of generation being exported to the wider network is increasing. Increasing the branch "base flow" would act to decrease the NUF allocation for that asset.

Thus it is seen that adding a new generation to a network, may either increase or decrease a nodal demands NUF at each voltage level dependant on the relative network locations, network impedances, branch ratings and existing demand and generation flows in the network.

As noted earlier, when a new generator alters the maximum contingency flow of a branch the amount by which the NUF factor is altered would depend on the size of the change in flow in proportion to the branch rating. Whether a branches NUF allocation increases or decreases in a generation dominated asset would depend on the magnitude of this change combined with the magnitude of change in 'base flow' compared to the existing 'base flow load'.

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4.2.1 Impact on specific example network

Figure 4-3 Example generation dominant network
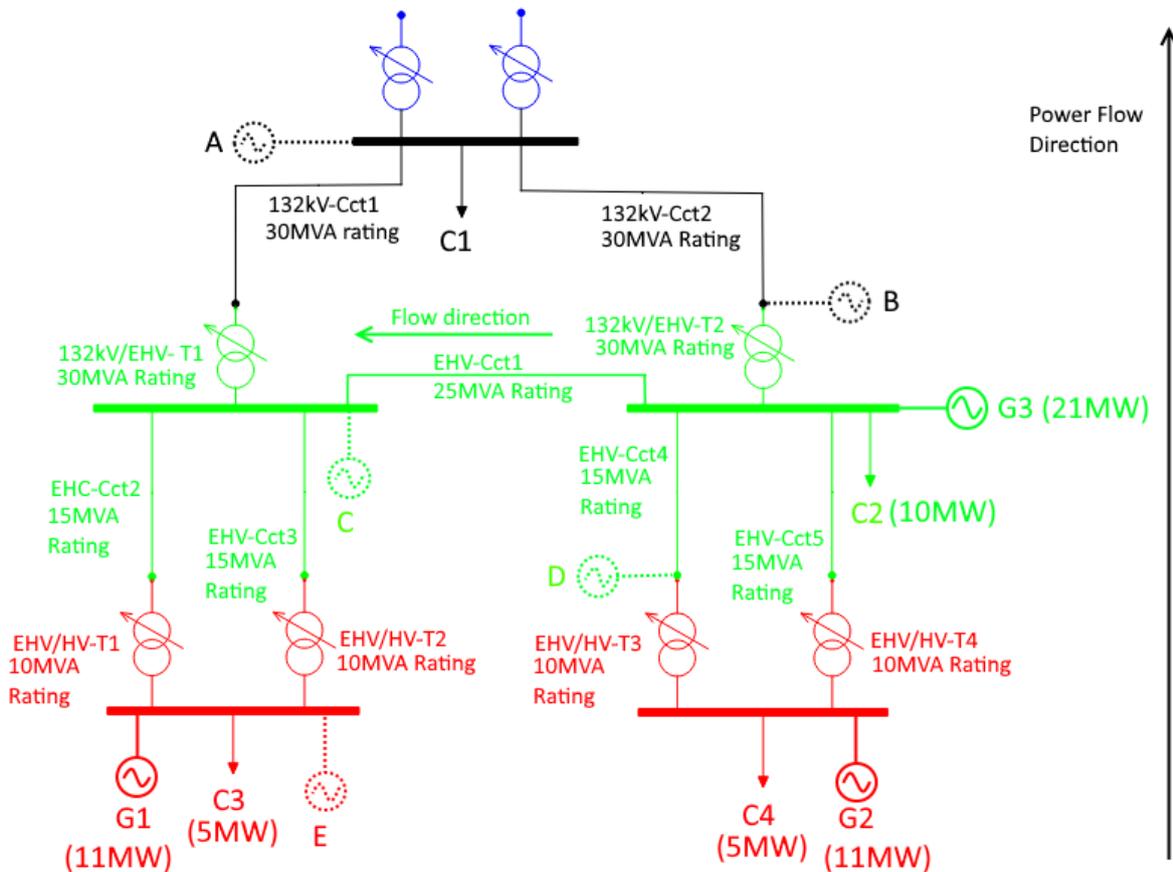
Considering the generation dominant network shown in Figure 4-3, the impact on the four customers of an additional 3 MW generator is described below:

In this network the direction of flow on circuit EHV-Cct1 is as shown in Figure 4-3 during intact network conditions and during the maximum contingency flow, which occurs when circuit 132kV-Cct2 is outaged. In this generation dominant case the direction of flow is exporting power from LV to the external transmission network.

Adding a new generator at location A, would not impact the base or maximum contingency flow on branches.

A new generator at location B may;

- increase the base flow on the assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2 and EHV-Cct1;
- increase the maximum contingency flow on all these assets.

A new generator at location C may;

- increase the base flow on the assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2 ;
- decrease base flow on the branch EHV-Cct1, base flow is decreased on this branch, as the direction of base flow is as indicated in Figure 4-3;

- increase the maximum contingency flow on assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2;
- maximum contingency flow on the branch EHV-Cct1 may be unchanged.

A new generator at location D may;

- increase the base flow on the assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2 and EHV-Cct1, along with the circuits supplying demand C4, EHV-Cct4, EHV-Cct5 and EHV/HV-T4;
- decrease base flow on the left hand side transformer supplying demand C4, EHV/HV-T3;
- increase the maximum contingency flow on all these assets.

A new generator at location E may;

- increase the base flow on the assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2, along with the circuits supplying demand C3, EHV-Cct3, EHV-Cct4, EHV/HV-T1 and EHV/HV-T2;
- decrease base flow on the EHV branch connecting the EHV busbars, EHV-Cct1;
- increase the maximum contingency flow the assets 132kV-Cct1, 132kV-Cct2, 132kV/EHV-T1, 132kV/EHV-T2, along with the circuits supplying demand C3, EHV-Cct3, EHV-Cct4, EHV/HV-T1 and EHV/HV-T2.

As discussed in section 4.1 these effects will only impact the NUF of a particular nodal demand if that demand 'uses' the network assets. The network assets used by the demands is reproduced again in Table 4-3 and the effect on NUFs in shown in Table 4-4.

Table 4-3 Branches used by hypothetical customers by voltage level

Customer	Voltage level				
	132kV	132kV/EHV	EHV	EHV/HV	132kV/HV
C1					
C2	Used	Used	Used		
C3	Used	Used	Used	Used	
C4	Used	Used	Used	Used	

☐	Not used
�◼	Used

Table 4-4 Potential impact maximum contingency flow of branches by voltage level

Generator location	Factor	Voltage level				
		132kV	132kV/EHV	EHV	EHV/HV	132kV/HV
A	Overall NUF					
	Max Con Flow					
	Base Flow					
B	Overall NUF	🟥	🟩	🟥		
	Max Con Flow	🟥	🟥	🟥		
	Base Flow	🟩	🟩	🟩		
C	Overall NUF	🟩	🟩	🟥		
	Max Con Flow	🟥	🟥			
	Base Flow	🟩	🟩	🟥		
D	Overall NUF	🟥	🟥	🟩	🟥	
	Max Con Flow	🟥	🟥	🟥	🟥	
	Base Flow	🟩	🟩	🟩	🟥🟩	
E	Overall NUF	🟩	🟩	🟥		
	Max Con Flow	🟥	🟥	🟥	🟥	
	Base Flow	🟩	🟩	🟩🟥	🟩	

Legend:

☐ No Change

🟩 (Factor increases & Acts to decrease NUF) / Overall NUF decrease

🟥 (Factor increases & Acts to increase NUF) / Overall NUF increase

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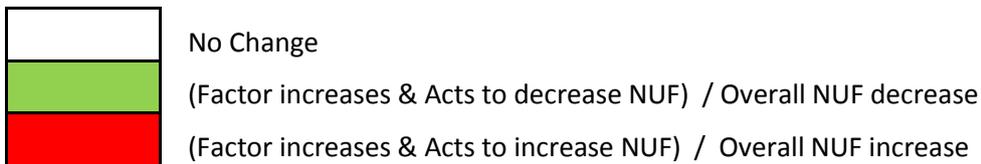
4.3   Summary

Adding a new generator does not change the branches 'used' by a nodal demand when calculating NUFs.

In demand dominant networks the new generator may decrease the maximum contingency flow on those branches which a nodal demand uses, which may generally decrease NUFs. There is a case where the maximum contingency flow on a demand dominant branch may be increased by the addition of a new generator, which would increase NUFs.

In a generation dominant network adding a new generator may increase the maximum contingency flow on branches used by a nodal demand, which may increase NUFs. The base flow on branches used by the nodal demand, however, may either increase or decrease depending on branch/load/generator locations which would either decrease or increase NUF values correspondingly. The overall combined effect on NUF factors would depend on the magnitude of MW flow changes caused compared to the branch ratings and base flow load values.

When a new generator alters the maximum contingency flow of a branch the amount by which the NUF factor is altered would depend on the size of the change in flow in proportion to the branch rating. Whether a branches NUF allocation increases or decreases in a generation dominated asset would further depend on the magnitude of this change combined with the magnitude of change in 'base flow' compared to 'base flow load'.

5   Glossary of Terms

Term	Meaning
Base flow	The "Base flow" in an asset, is the power flow in the asset due to network demand and generation under the system intact (N-0) condition before any contingencies are considered.
Base flow load	The "Base flow load" in an asset, is the power flow in the asset due to network demand only, with all embedded generators switched off, under the system intact (N-0) condition before any contingencies are considered.
Maximum contingency flow	The "Maximum contingency flow" in an asset, is the maximum power flow in the asset, due to network demand and generation, across all simulated network contingencies/outages.
Maximum demand	The network demand data that is applied to the maximum demand scenario, which reflects the maximum loading conditions in the network.
Minimum demand	The network demand data that is applied to the minimum demand scenario, which reflects the minimum loading conditions in the network.
Workstream B	Three workstreams were established to develop the EDCM. Workstream A steered development of the power flow modelling. Workstream B developed the tariff/commercial model.