DG impact assessment approach under Code xx

1. Preface

This note follows preliminary discussions between the Electricity Authority (Authority) since late November 2017 on how Transpower might analyse whether DG is helping to avoid transmission costs. In those discussions the Authority explained that it wanted to avoid significant incremental work for Transpower's planners (reflecting concerns flagged by Transpower) and wanted Transpower to utilise standard planning practices.

The Authority proposed using a GRS framework that utilised existing process for Transpower's main planning report, the Transmission Planning Report (TPR) which incorporates the Grid Reliability Report.

The Authority advised that Transpower would not have to identify whether individual DG installations avoided transmission cost, but whether DG in particular areas of the grid did so [areas not defined but we discussed GXP and TPR regions].

Transpower would like to agree the analytical approach with the Authority before we start the analysis. We consider that this will allow the analysis to be completed in the most robust, cost effective and timely manner and to minimise the risk of misunderstanding, dispute or rework.

The purpose of this note is to set out Transpower's preliminary views, building on discussions with the Authority to date, on the analytical approach that we will adopt. It is for discussion with the Authority and remains subject to approval by Transpower.

2. Introduction

On 6 December 2016, the Electricity Authority published its decision to amend the Distributed Generation Pricing Principles (DGPPs). This amendment requires Transpower to provide reports to the Authority that identifies which (if any) distributed generation is required for Transpower to meet the grid reliability standards (GRS) in each of the four pricing regions (Lower South Island, Lower North Island, Upper North Island and Upper South Island).

Transpower must by 15 March 2017, provide such report for the Lower South Island region covering the period from 1 April 2017 to 31 March 2020.

The Authority will review Transpower's report and either accept or decline it. If declined the Authority can direct Transpower amend its report. The report is an input to an Authority decision on publishing a list of distributed generation for the relevant region that will be eligible for ACOT payments.

Only distributed generation (DG) connected as at 6 December 2016 would be eligible for any ACOT payments.

3. Our proposed approach for the first assessment

We have outlined an approach below based on consultation with experts from within our business on what is practicably deliverable to the Authority on 15 March 2017. Our approach takes as the starting assumption the role of the Transmission Planning Report Process for any GRS assessment, specifically the TPR is the vehicle for the Grid Reliability Report under 12. 76. We publish the TPR at not more than 2 yearly intervals, usually in June/July. To undertake system studies and write the report usually takes around 4 months. Given the deadlines for the reports' production we propose close alignment with the inputs and tools for our the most recent TPR.

Our approach assesses the impact of DG on the transmission grid using assumptions, models and approach that is closely aligned with our TPR process. This includes assessing:

- DG required to meet N-1 at GXP's
- Impact of DG at the regional level
- Whether DG has an impact on the grid backbone constraints.

We have made some key assumptions in the approach for the first assessment which we would want to clarify with the Authority and which will inform the approach for future assessments.

3.1. TPR process is for the Grid Reliability Report

The Grid Reliability Report under 12.76 is a forecast of whether the system can meet N-1 contingency. The GRR is a forward looking report that is the starting point for identification of possible areas where the GRS may not be met. Specifically, under the benchmark agreement clause 40, if a GRR repost identifies the N-1 criterion will not be met in the next five years and a connection asset is the cause, then Transpower must investigate further to identify if the GRS economic standard is met, or not.

3.2. Use TPR region definitions

The TPR process does not organise grid information by the four pricing regions. To maintain the tools and settings for the TPR we will need to align the regions for the DG impact assessment with the current 13 transmission planning regions and the grid backbone. For the first assessment due on 15 March 2017, we will use the existing DigSilent model from the 2016 TPR assessment. We will use our load forecast at the GXP, transmission planning region, and island level.

We will model the grid backbone to assess the potential benefits not observable at the GXP or single regional level. This could help illustrate the aggregate impact of DG on interregional power flows.

3.3. Aggregate DG impact

In line with the policy intent we will assess the impact of the aggregate DG at a GXP. We understand from the policy development that we are not expected to consider alternate combinations of DG generation behind a GXP.

For the regional assessment we will aggregate the DG impact within the region to ascertain if the aggregate DG behind a GXP or within a region has an impact. To assess the impact of specific combinations of DG within a region on transmission constraints/voltages, we would need to assess many potential combinations of DG within the region which would significantly increase the analytical task and time needed for it.

3.4. Demand forecast

To assess the impact of DG it would be necessary to determine the load forecast over the assessment period excluding the effects of DG (i.e. DG added back with DG output determined separately - see 2.7 below). These load forecasts would be at the GXP, transmission planning region and island level. In addition to the load forecast we would need to understand the potential impact on the load power factor excluding the effects of the DG.

We will also have to estimate changes in demand behaviour flowing from the removal of the RCPD price signal (from 31 August 2018, on the Authority's proposed implementation timetable).

3.5. Power factor

In areas of the grid where voltage issues are critical, the power factor implications of removing DG will be important. We will use the power factor forecast at each individual GXP. Where information on the DG impact on load power factor is not available, we would need to make some simplifying assumptions.

3.6. Grid-connected generation assumptions

We propose to use the same modelling approach to grid-connected generation as in our TPR assessment process. This involves:

- Considering generation scenarios that stress the regional transmission grid
- Considering a range of generation scenarios to assess the wider transmission regions including the grid back bone.

In keeping with our TPR modelling approach, we will include committed future generation in our assessment. These committed generators have a very high likelihood of being implemented.

3.7. DG assumptions

In a "with" and "without" aggregate DG analysis, we will need to use reconciliation level data for aggregate DG at the GXP.

3.8. Impact assessment duration

The Authority has indicated that the initial DG assessment would be for the period 01 April 2017 to 31 March 2020.

To retain efficiencies with our TPR process, we will use its assessment period of 15 years which will cover the required period. This would provide additional information for the Authority and for the DG about their impact (if any) over a longer time frame.

4. Assessment procedure

This section outlines the steps we would take for the assessment.

4.1. Base case ("with DG") assessment

To determine the potential impact of DG, a credible counterfactual solve is required. For this an assessment of N-1 contingency analysis "with DG" in service would be undertaken.

4.2. GXP-level analysis

Our GXP-level analysis provides an assessment on the impact of DG at the individual GXPs. For the modelled generation-demand-network configuration scenario:

i. *Assess the "without DG" scenario:* Assume aggregate DG at the GXP not in service and undertake an N-1 contingency analysis for supply transformers and spur connections. Determine if there is any impact on transmission constraints or voltages under base case or N-1 contingency scenarios.
ii. *Impact assessment:* If between the "with DG" and "without DG" scenarios there is a difference in the transmission overload and/or voltage issues, then this is a result of the DG. Therefore, DG at the GXP has an impact. Note, the above assessment would only include impact at and into the GXP.
iii. Repeat steps ii and iii for each GXP with DG.

4.3. Region-wide analysis

For our regional analysis, we have assumed this would apply to non-core grid issues. For modelled generation-demand-network configuration scenario[1]:

i. *Assess the "without DG" scenario:* Assume aggregate DG in the region is not in service except for those DG[2] deemed to have an impact from the GXP-level analysis. Undertake power flow analysis to determine if there is any impact (transmission overload/voltage/stability issues) under base case and N-1 contingency states on the regional non-core grid.
ii. *Impact assessment:* If between the "with DG" and "without DG" scenarios there is a difference in transmission constraint (and or voltage) issues, then this is due to the presence of the DG. Therefore, DG within the region has an impact on transmission constraints, voltage or stability issues. Note the above assessment not only includes impact <u>within the region</u>
iii. Repeat steps i to ii for each region with DG.

4.4. Grid backbone

The grid back bone analysis could be a repeat of the regional analysis but with more scenarios that will highlight import and export issues. Hence our assessment for the DG would be on this wider transmission network. We consider further internal discussion is needed to develop and decide an appropriate approach, below is an example of a possible approach.

For each generation-demand-network configuration scenario[3]:

i. *Assess the "without DG" scenario:* Assume aggregate DG in the grid backbone region not in service <u>except</u> for DG[4] deemed to have an impact from the GXP-level or region-wide analysis. Undertake power flow analysis to determine if there are any impacts on transmission constraints, voltages or stability under base case or N-1 contingency scenarios

[1] For this generation scenario we would use a grid generation scenario that stresses the regional transmission system.
[2] This is aggregate DG at the GXP.
[3] We would use the same generation scenarios as used in the TPR grid backbone analysis.
[4] Again this is aggregate DG at the GXP.

ii. *Impact assessment:* If between the "with DG" and "without DG" scenarios there is a difference in the transmission overload/voltage issues, this is due to the presence of the DG. Therefore, DG within the grid backbone region has an impact. Note the above assessment only includes the impact on the grid backbone.

iii. Repeat steps i to ii for each aggregate region with DG.

5. Output/advice matrix

The output matrices below provide an indication of a potential summary of results from the DG impact analysis. This indicates whether the DG at the GXP or regional level has an impact on the transmission system or the scenarios in which the DG may have an impact at the grid backbone level.

Scenario assumptions

The details of each of the modelled scenarios would be described as part of the assumptions/ modelling details required by the Authority. These would be the assumptions as used in our most recent TPR process.

DG modelling assumptions

The details of assumptions on DG modelled output for each of the scenarios would also be required. We consider an agreed (consulted) approach with the Authority on such modelling (which could incorporate Transpower's standard procedures) will aid transparency and repeatability of approach.

GXP-level analysis

GXP name	Scenario 1 (describe)	Scenario 2	…
A	X	X	
B			
Etc.			

Region-level analysis

Region	Scenario 1	Scenario 2	…
One, with GXPs A, B…	X		
Two, with other GXPs			
Etc.			

Grid Backbone analysis

Backbone region	Scenario 1	Scenario 2	…
One and two		X	
Etc.			

6. Analytical approach – detail to work through

- In using an N-1 assessment approach, there could be instances where DG could be beneficial to the grid in some scenarios but not beneficial in others. We could consider DG to be beneficial if it positively impacts any scenario. Without detailed economic analysis for each issue we cannot be more specific than this.

- We may need to know how to model small generators' response to low voltage events. Without knowing how they respond to voltage events we cannot say if we are currently modelling their impact, or not. If we take DG away from our forecasts and models, without accurately reflecting their contribution to voltage stability we may miss where DG has a beneficial impact to the grid.
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- Where there is an N-1 issue both with and without the DG we need to understand if the presence of DG reduces the severity of the constraint, in order to determine if the DG is beneficial to the grid. Where the outcome is not obvious we would need to make an assumption on whether the DG is offering additional value.
- Load management: We do not know, but will have to estimate, changes in demand behaviour flowing from the removal of the RCPD price signal (from 31 August 2018, on the Authority's proposed implementation timetable). A similar issue exists for changes in DG behaviour.
- Maintenance: Some DG can assist with the scheduling of equipment planned outages. This has benefits as N-1 system security might otherwise not be possible without the DG during the planned outage. Without the DG the outage window availability may shrink, or be non-existent. However, our TPR process does not include any consideration of how DG can positively impact the ability for TP to get outages for maintenance/repairs.

7. Initial Case study to raise any further analytical issues

To better understand the potential issues we will likely be considering a case study within the Lower South Island region. We believe that this approach will allow us to quickly uncover other potential issues from those already identified and discussed above.