Regional Development Plan

Process Report

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This report is to document the process and methodology involved with completing an RDP and to outline the learning points and recommendations for future RDPs.

Contents

1. What is a Regional Development Program?

The Regional Development Programs (RDPs) were set up to provide detailed analysis of areas of the network which have large amounts of Distributed Energy Resource (DER) and known transmission / distribution network issues in accommodating that DER. The idea is to use this analysis to innovate and push the boundaries of current thinking with a "design by doing" approach to resolving the issues pushing towards Distribution System Operator (DSO) type solutions and informing thinking for the DSO debate.

By solving a specific case study that has a pressing need to improve outcomes for customers in innovative ways, it is possible to make progress faster than the more conventional method of agreeing changes in approach at industry forums before making changes to the way the industry works. While there are risks that working in this way leads to a lack of standardisation across the GB network, this has been successfully managed by close cooperation and using the regional development programs as case studies for the Energy Networks Association (ENA) Open Networks Project. Techniques and processes used within the RDPs will be replicated across other network areas as appropriate, resulting in innovative approaches being deployed much more rapidly.

Initially the RDPs have been set up on a project basis, but as the techniques and findings of the RDPs move into regular practice, it is envisaged that the RDP approach will continue to develop into a series of Business as Usual (BAU) developments.

2. What processes are involved in an RDP?

Completing a detailed joint transmission and distribution network analysis required multiple discrete stages before recommendations for future strategy could be derived.

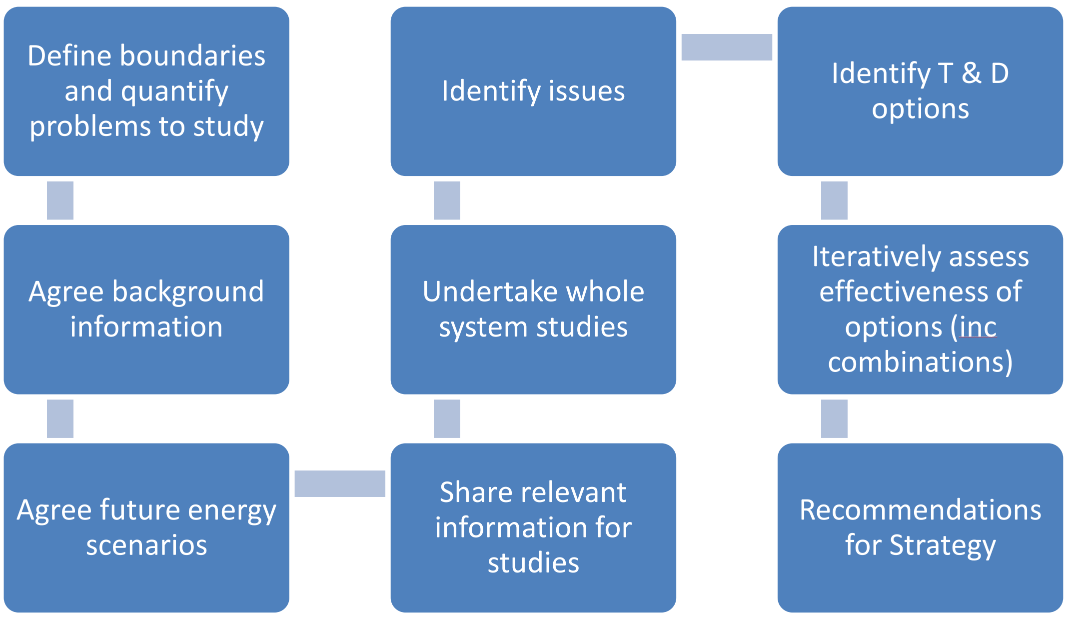

Figure 1 – RDP high level processes

2.1 Problem quantification

In order to fully understand and quantify the impacts of demand and DER uptake on the whole electricity system, the scenarios being studied need to be decided and fixed. The volume and distribution of the various technologies need to be described in consistent terms in such a way that it is possible to repeat the studies for both transmission and distribution network studies and ensure the power flows are comparable.

Within the National Grid and Western Power Distribution RDP, the same underlying scenario modelling framework was used across both transmission and distribution network studies. Data on the potential for demand and DER installations from WPD's Strategic Network Investment reports was used to describe the regional Electricity Supply Areas (ESAs) uptake trajectories, based on the scenarios used under National Grid's national Future Energy Scenario outlook. ESAs tend to be based around the areas of network supplied by Bulk Supply Points, though some ESAs may be split up further, depending on configuration.

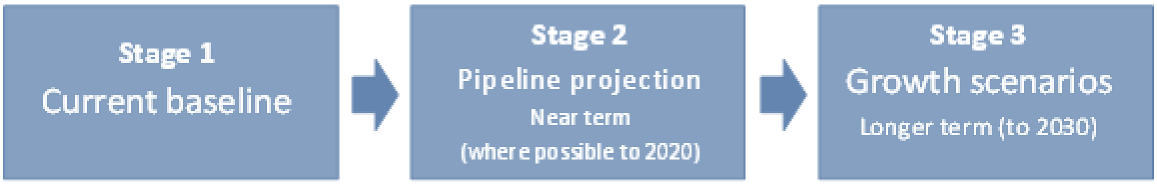

Figure 2 – Stages in developing growth scenario data

- Stage 1 - A baseline assessment – taken from the current status of connected connections. The baseline has a high degree of accuracy as it is based on the DNO's network connection database, reconciled with further desktop research to address errors and inconsistencies.

- Stage 2 - A pipeline assessment – looking out to two to four years where possible. The pipeline has a reasonable degree of accuracy since it is based on the DNO's network connection agreement database reconciled with the BEIS planning database, telephone and internet research and understanding of the current market conditions. It also takes into account the accepted but not yet connected enquiries. For some technologies, there will be no pipeline given the current stalling of the market and/or uncertainties about near term growth rates.

- Stage 3 - A scenario projection – out to 2030 and potentially beyond. The scenarios are based on National Grid's FES, assessed and interpreted to take into consideration the specific local resources, constraints and market conditions. To inform market insights for each technology, detailed interviews with renewable energy developers and investors have been undertaken, as well as a consultation event to gather local specific views and information.

By building the uptake scenarios from a local level upwards, the distribution of installations can be more accurately aligned to the current installed position and also include better forecasting predictions by using the DNO's pipeline of future installations.

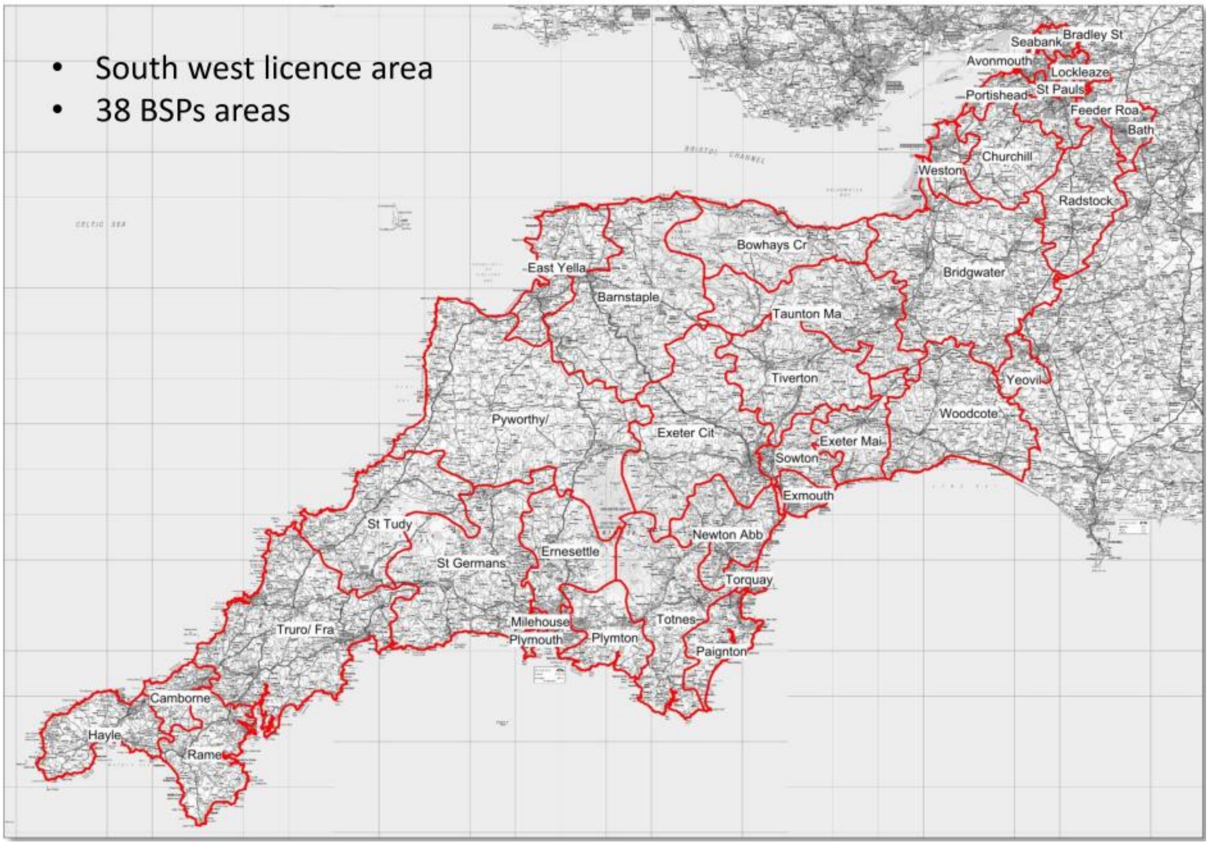

Figure 3 – Map of BSP/ESA areas in the South West

The following factors are considered at a local BSP/ESA area when determining the uptake scenario numbers:

- Current 2017 distributed generation capacity connected
- A pipeline analysis of distributed generation capacity (up to 2020 where possible)
- Scenario analysis of distributed generation technology capacity growth to 2030, building on the FES
- Scenario analysis of potential future demand resulting from new residential and commercial development, heat pumps and electric vehicles from 2016 to 2030, building on the FES
- Scenario analysis of the development of storage

The mutually agreed data on the installed capacity, technology type and location are shared between transmission and distribution network companies for modelling purposed.

Summary of lessons learned and recommendations

- The accepted not yet connected connections database held by the DNO may include a significant amount of capacity which, whilst the DNO is committed to delivering, is not delivered through to energisation. This is particularly affected by changes in technology pricing, incentive mechanisms and subsidies.

- It may be prudent to apply scenario modelling techniques on the accepted not yet connected database so that there is level of attrition for connection enquires, depending on political, social, economic and technological trends. This will be most relevant where there is a large committed pipeline of capacity.
- As ESAs are created by using the boundaries of network assets, these will change as the network is reconfigured and augmented in time. This may mean it is not possible to identically compare ESAs in subsequent studies

2.2 Identify Scenarios for Study

Once the underlying data set to be used is mutually agreed, the number of scenarios and timelines to be studied must also be decided. Using a scenario modelling framework, such as the methodology described in National Grid's Future Energy Scenario (FES) outlook, allows a range of future demand and generation uptake scenarios to be determined. Many of the installed capacities will be the same for different scenarios at different timescales, so choosing scenarios based upon the installed capacity, rather than a time period or economic/political outlook may reduce the number of scenarios required to be studied. Where the technology type of generation varies significantly between scenarios, then this approach will not hold true and should not be applied.

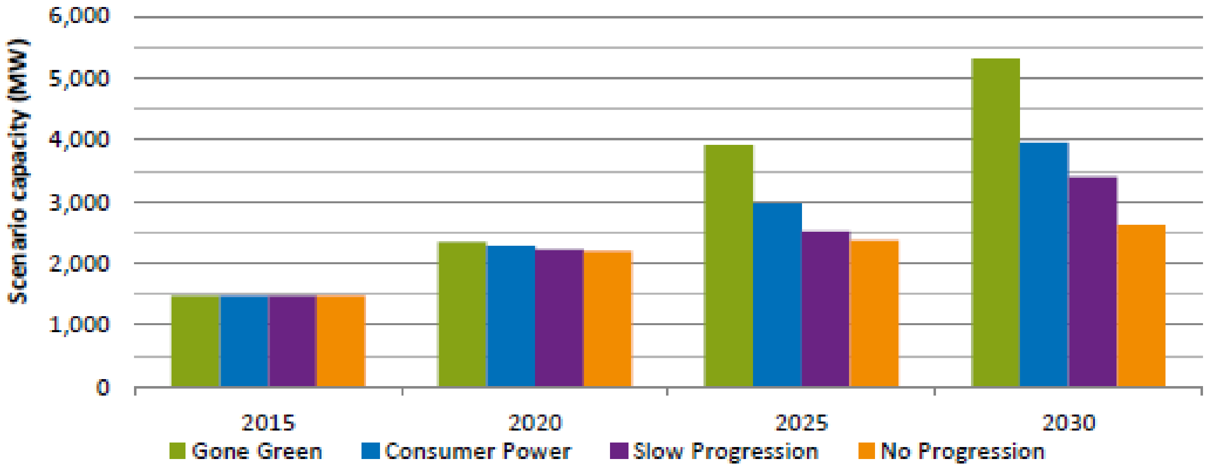

Figure 4 - DG capacity growth 2015 to 2030 under the four scenarios

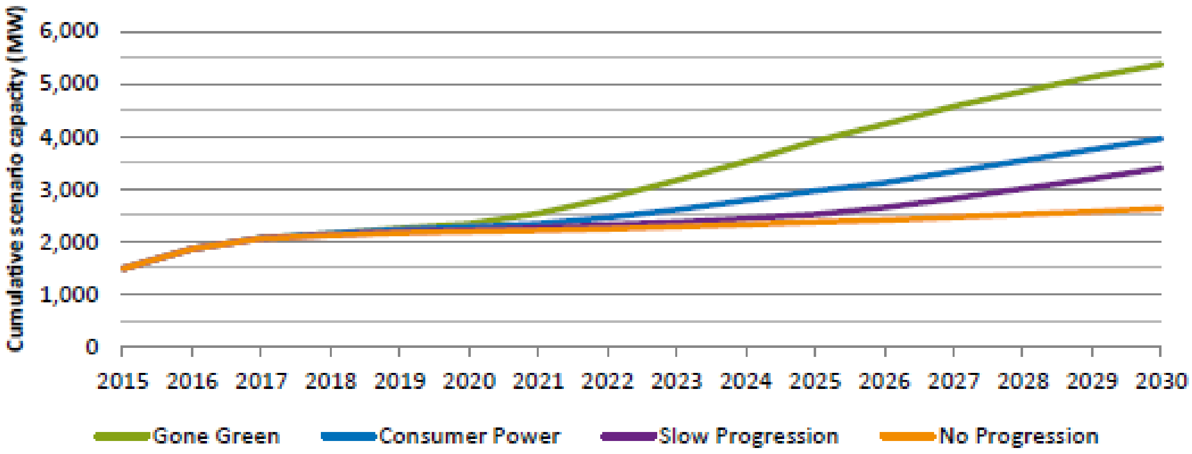

Figure 5 - Total renewable distributed generation capacity growth in WPD South West licence area from 2015 to 2030 under each scenario

Within this joint RDP in the South West, it was decided to study the network based upon a 3GW, 4GW and 5GW installed DG scenario. This allowed the total dispatch levels to be fixed in order to provide a consistent route to modelling the power flows on both transmission and distribution systems. It also meant that the reinforcement recommendations that ensured the network was kept within limits at the power flows modelled, would also hold true for other combinations of installed capacity and generation mix that resulted in lower power flows.

The table below shows the template followed for determining the installed capacity per technology type and the technology specific diversity factor which results in a total dispatched generation figure.

Generator Technology Type	Installed Capacity (MW)	Diversity	Dispatch (MW)
Hydro	6.12	39.60%	2.42
Landfill Gas	187.30	48.99%	91.76
Medium CHP	9.50	12.00%	1.14
Mini CHP	3.56	35.76%	1.27
Mixed	5.85	12.46%	0.73
Onshore Wind	324.00	59.93%	194.17
Other	695.60	23.82%	165.69
Photovoltaic	1394.00	86.70%	1208.60
Small CHP	16.80	15.43%	2.59
Battery Storage	188.45	-50.00%	-94.23
Total	2831.18		1574.15

Figure 6 – Table of generation capacity and applied diversity

Any recommendations for intervention made off the back of this analysis will still be correct should the uptake trajectory be more rapid or delayed. The timing of the intervention required will just need to be adjusted.

Through identifying the potential installed capacities, the extent as to how likely the largest installed capacities are to run concurrently should inform which representative study days will result in maximum loading conditions on the network.

<u>Summary of lessons learned and recommendations</u>

- Modelling every single technology type individually within each of the geographic areas chosen for the study will result in a significant number of nodes being created. Some rationalisation of the technologies will be required, but the level to which that grouping occurs should be carefully considered else it may limit the analysis carried out subsequently.
- PV, Wind, Storage and Other are suggested groupings, however some further sub-division of the categories may be required if there is another dominating technology within the 'Other' category.
- Whilst the growth of renewables is likely to be the main focus, other generation types should also be considered as they may impact the total energy flows to a greater extent than the more intermittent technology types.
- Category groupings will also be affected by the extent as to how dispatchable the technologies are and how much their dispatch profiles are affected by market behaviour.
- Size of installed capacities for each technology type and the coincidence of dispatch with other types will inform the studies needed to determine maximum loading conditions.
- It is recommended that the industry work together to determine a consistent methodology for determining future energy scenarios so that this methodology can best inform further whole system study work. Having a consistent methodology and better sharing of data would reduce the time spent within the first RDPs on aligning data and scenarios between Transmission and Distribution. ON2018 WS1 P5 and WS1 P12 will be best placed to take this forward.

2.3 Determine Generation Diversity Factors

In order to realistically model the behaviour of generator output in the region being studied, generation diversity factors (load factors) need to be calculated for different generator technology types. By multiplying the installed capacity for each generator technology type by its respective diversity factor for the period being studied, it is possible to obtain a realistic maximum power export (dispatch) for each generator technology in the region. This method yields more accurate power flows when compare to the tradition method of modelling generator output as 1pu of installed capacity.

Diversity factors should be calculated for all the known technology types listed in the installed capacity database. Some typical generation technology types are listed below:

- Hydro
- Landfill Gas
- Medium CHP
- Mini CHP
- Mixed
- Onshore Wind
- Other
- Photovoltaic

- Small CHP
- Waste Incineration

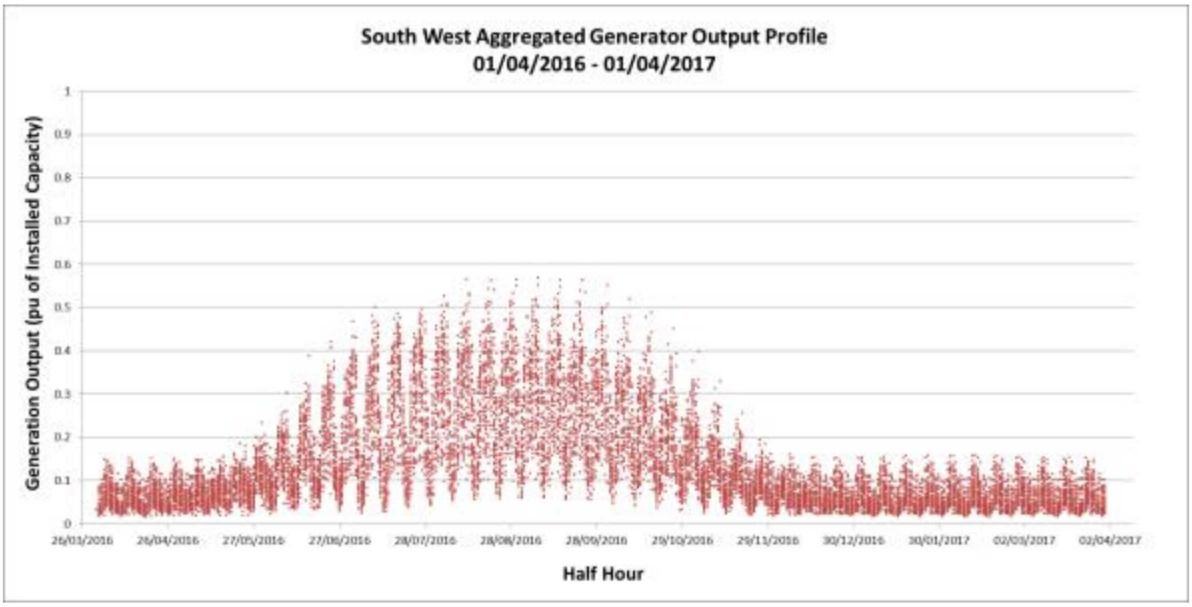

Figure 7 – Graph of South West Aggregated Generation Output Profile

Generator diversity factors are derived from generator export meter readings. For joint transmission and distribution studies, this should include sites with an installed capacity greater than 1MW. The export meter readings for all generators should be aggregated together to produce an annual total generator output profile for the region. The total generation output for each half hour can be plotted and normalised against the total installed generation capacity. Any trends that influence the maximum loadings can be seen observed through this process. In the example above, it can be seen that the generation in the region is solar dominated.

By restructuring the same generator export data used to determine the annual profile, the annual generation persistence curve can be plotted for the region. The persistence curve is created by reordering the aggregated half hourly meter readings in descending order.

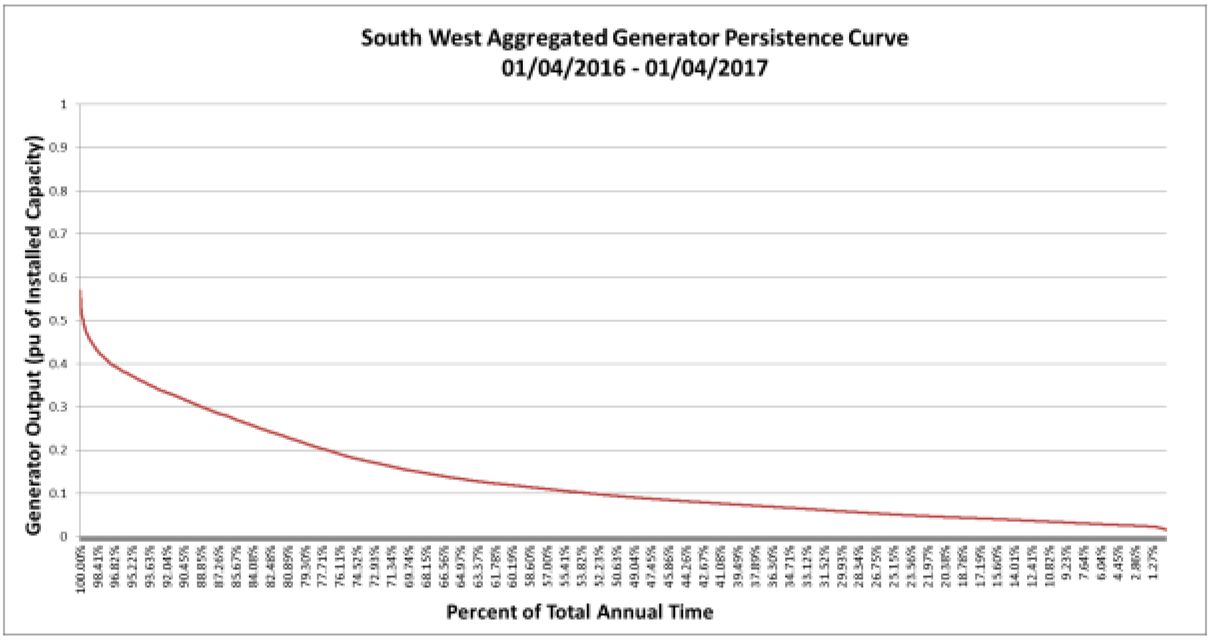

Figure 8 - Graph of South West Aggregated Generation Duration

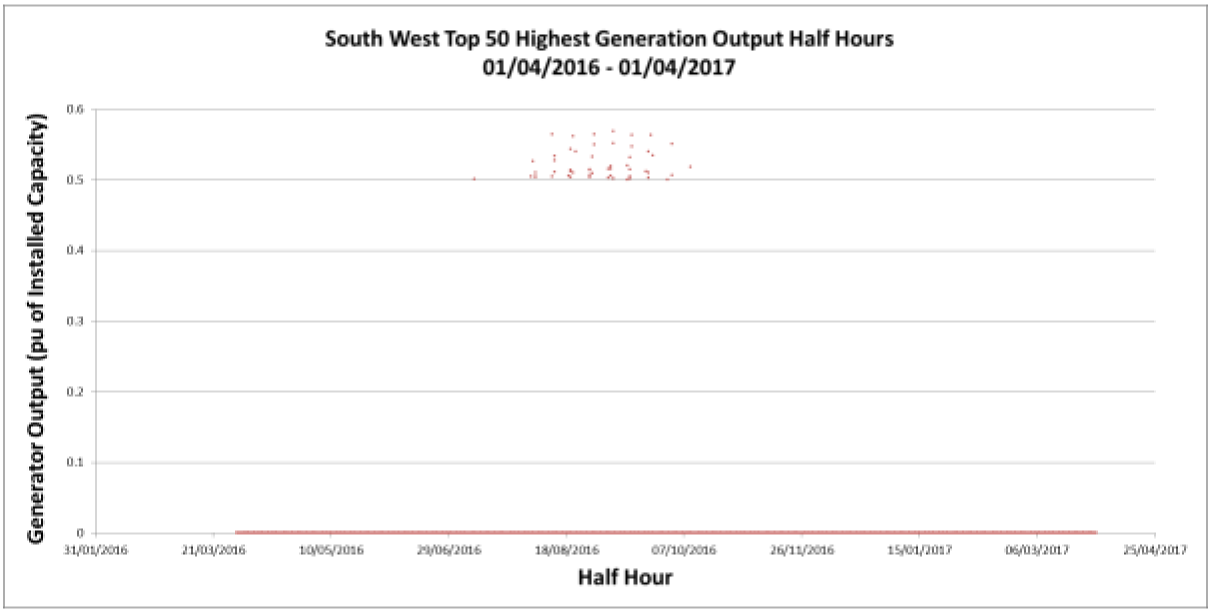

Figure 9 - Graph of South West Aggregated Generation Output – Top 50 half hours

Using the annual aggregated generation output profile and the aggregated generator persistence curve, the highest generation output half hours can be selected and plotted. In the above figure, the top 50 half hours have been plotted. It can be seen that due to the amount of solar generation in the region that top 50 highest output half hours occur in the summer. This sample data sample also represents the most onerous power flows on the whole electrical system.

In this example, the top 50 highest half hours account for 0.3% of the total annual time, but 0.98% of the total annual generated energy. The top 50 highest generator output half hours can be used as the sample data for calculating the most onerous generator diversity factors. Generator diversity factors can be calculated in the following way:

- **Step 1**

For each of the top 50 highest generator output half hours the generation output for each of the generator technologies should be found. As an example, the number one highest half hour period from the data sample, broken down generator technology type, is shown in the table below. It should be noted that the generation power output for each technology type is expressed in per unit values of the respective installed capacity.

Generator Technology Type	Generator Output (pu of Generator Installed Capacity)
Hydro	25.45 %
Landfill Gas	21.84 %
Medium CHP	12.00 %
Mini CHP	34.04%
Mixed	10.39 %
Onshore Wind	53.13 %
Other	23.82 %
Photovoltaic	75.22 %
Small CHP	3.34 %
Waste Incineration	39.74 %

Figure 10 – Generation diversity per technology type – single half hour

- **Step 2**

Using the top 50 highest generator output half hours, the highest generation output for each technology type can be chosen. The table below shows the final generation technology type diversity factors.

Generator Technology Type	Generator Output (pu of Generator Installed Capacity)
Hydro	39.60 %
Landfill Gas	48.99 %
Medium CHP	12.00%
Mini CHP	35.76 %
Mixed	12.46 %
Onshore Wind	59.93 %
Other	23.82 %
Photovoltaic	86.70 %
Small CHP	15.43 %
Waste Incineration	41.27 %

Figure 11 – Generation diversity per technology type – average of top 50 half hours

Once the likely timing and seasonality of the maximum generation output conditions have been calculated, the underlying demand should also be calculated to see if this changes. For certain metrological conditions, the underlying demand will be fairly predictable – e.g.for PV dominated networks, Summer midday demand will remain broadly consistent. However, for other conditions there may be significant fluctuations with the underlying demand and a more onerous demand contribution may need to be assumed – e.g. networks with Wind generation dominating the network flow will have export peaks not necessarily coincident with favourable demand profiles.

Summary of lessons learned and recommendations

- As it is not practical to do annual time-series modelling to determine the maximum loading conditions, the dispatch studies being modelled need to be determined by selecting the current peak loading periods of the network and understanding the individual technology loading contributions.
- For areas of network where the generation mix is mature, then these studies are unlikely to change, however, where there is a future energy scenario which predicts a deviation in the generation mix, the studies may need to be revisited to ensure they remain representative of the future maximum dispatch conditions.
- The coincidence of demand against generation peak also needs to be considered as a variable. Care needs to be taken to ensure the coincidence of generation and demand does not change across the timeline being studied, in so far that it would impact on the validity of the study.

2.4 Identify and Agree Network to Study

The boundary of the network to be studied within the whole system study and the classes of asset to be included in the model needs to be defined. Ideally, a single model will be used for all studies being undertaken, however as whole system studies will require both transmission and distribution system operator planners to run studies, then due to differences in modelling software used within the respective companies, it may be necessary to have two separate models.

If two, or more, separate models are being used, then sufficient modelling information must be shared in order to ensure consistency between the studies.

Generally, the transmission network model will have a simplified version of the distribution system associated with it, and vice versa. The extent to which each model accurately reflects the network contained within the other model will determine the confidence in this approach.

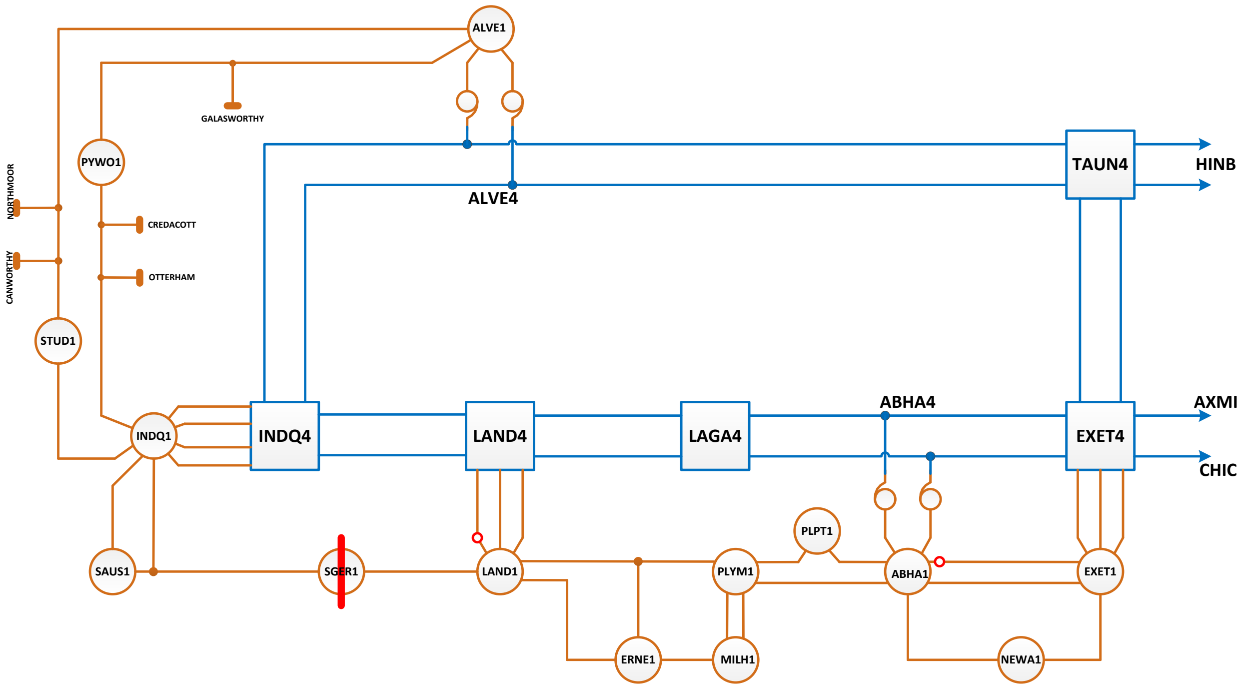

Figure 12 - an example transmission and distribution network for whole system analysis

<u>Summary of lessons learned and recommendations</u>

- Differences in modelling tools and historical datasets used between Transmission and Distribution System Operators may mean it is not practicable to use a single shared network model.
- When using separate network models it is not realistic to expect full alignment at the same granularity for all voltage levels, however, the differences in network models used can be mitigated by ensuring the voltage levels adjacent to the boundary are closely aligned in both transmission and distribution models.

2.5 Joint Modelling (Whole System Study) Methodology

The concept of Whole System Planning is to approach the technical issues as a single entity (SO, TO,DSO/DNOs and generators) and come up with the solution that is best for the consumer, based on the criteria of it being most economic and efficient. Asset build and operational mitigations (using a mixture of market driven and existing mandated services) are both considered to find the lowest cost solution as seen by the consumer to meet the requirements of the scenarios, with due regard to the uncertainty in generation outcome the scenarios describe. All solutions are costed on an equal basis regardless of who, under current regulation, would bear that cost.

The studies were carried out for three different DER dispatch level 2020, 2025 and 2030 as identified in the scenarios section.

2.5.1 Distribution Modelling

Distribution network modelling considers steady state flows across the distribution assets and ensures they remain within limits. Dynamic or transient studies are not undertaken by the DNO, however, operating the assets within the original designed capacity will ensure voltage step changes are within limits.

By using conventional network study tools to analyse the overloads observed for the various uptake scenarios under both intact and credible outage conditions, the circuits and assets in need of mitigation through curtailment or reinforcement can be identified. Two studies will be undertaken, with differing diversities of generation output:

Network Maximum Credible Loading Study: In order to determine likely maximum curtailment requirements, this study analyses a credible maximum generation output profile, as detailed above, with coincident demand loadings. Both intact network and credible outage conditions are considered.

Generators behind these circuits and assets can then be throttled down, in order of maximum sensitivity, to achieve a first-pass technical best curtailment. This technical best curtailment is only possible if the contractual principles of access allow for this method. Traditional distribution curtailment is enacted on a LIFO (last in, first out) basis, which, due to varying constraint sensitivities, will likely increase the volume of generation curtailment required to keep the network within limits.

Network Minimum Curtailment Study: This study reduces the output of generators affecting the circuits and assets in technical best order until the network remains within limits. Both intact network and credible outage conditions are considered and ANM is configured to run in pre-fault curtailment mode.

2.5.2 Transmission Modelling

A number of steady state and dynamic analysis were carried out to understand the network issues. All credible single and double circuit faults within the study zone are simulated under intact network and outage conditions. From the steady state simulation results, any fault/outage combination that indicates a voltage issue has been analysed using a dynamic simulation. The study looked to identify following issues within the study zone:

1. Thermal issues: Any fault that may overload any of the remaining circuits/assets.
2. Voltage issues:
    a. Steady state voltage violation – any voltage violation 3mins after fault clearance
    b. Voltage step changes – any voltage step changes outside the limit 3mins after fault clearance
    c. Fast voltage collapse – the study zone lacks any dynamic voltage support (ie synchronous generators or SVCs). Under certain scenario the voltage can reduce to zero rapidly within few hundred milliseconds from fault occurring and not recover.

3. G59 under voltage violation - Energy Networks Association's (ENA) recommendation G59 is advising small embedded generators on certain protection settings. One of the recommended protection settings is to disconnect generator if the connection point voltage drop below 0.8pu of nominal voltage and stays there for 500ms or longer.

Summary of lessons learned and recommendations
• System and Network operators will benefit from being able to more accurately model the network adjacent to their area of responsibility and by doing so, will find more potential solutions for mitigating issues. Any network models used for current practices should be expanded to include more detail of the adjacent network as the addition of such network information is no longer a restriction for present modelling tools and computing capability. • It should be recommended that distribution network operators begin to move from purely considering power flows for strategic network studies, to considering energy flows across a wide time period.

2.6 Steady state nodal comparison

To ensure all the models are aligned and broadly representative of each other, the flows between nodes should be compared so that the results can be corroborated.

By comparing the power flows at a number of the circuits being studied across both models, the validity of the results can be confirmed. Any significant variances can then be traced back to where the disparities between models are occurring and then rectified by an additional exchange of more accurate information.

Summary of lessons learned and recommendations
• Reactive power consumption behaviour of the models needs to be compared and potentially adjusted to ensure that under different loading scenarios, both models behave similarly

2.7 Apply asset ratings and limitations and identify non-compliances

Depending on the timing of the scenario being studied and any assumptions on network outages, different ratings will be applied to the assets. There can be a significant difference between ratings applied pre and post fault, so these must be correctly applied.

The rating applied may also vary depending on the load duration curve observed for the scenario being studied.

Following the application of the rating for the asset, any exceedances above the capability of the network can be identified as constraints.

Summary of lessons learned and recommendations
• The application of pre and post fault ratings can deliver significant benefits through applying post-fault curtailment as opposed to pre-fault curtailment, however this benefit is related to the difference between ratings.

2.8 Compare Exceedances, Challenge and Review Option Combinations

From the studies undertaken, a number of issues will be identified across a number of scenarios. Issues will take the form of voltage and thermal constraints, transient instability, voltage step changes or protection issues.

Some exceedances may be managed already by existing intertripping for specific conditions detailed in connection agreements. Where network access restrictions are not identified, then it may be possible to mitigate these constraints by network configuration.

Any further constraints will require more interventional techniques, such as reinforcement, balancing through storage or curtailment.

For efficient and economic whole system planning, conventional and non-conventional build techniques need to be assessed alongside non-build options.

Below is a list of credible mitigations identified in previous whole system studies:

- Reconductoring
- Reprofiling/Retensioning
- Intertripping
- Active Network Management
- Pre-fault curtailment (as part of network access)
- Pre-fault curtailment (as a service)
- Post-fault curtailment with post-fault overload ratings
- Storage as a service
- Protective reactive switching
- Statcom/SVC
- Synchronous compensation as a service
- Forced cooling for assets
- Dynamic Asset Ratings

One or more solutions (in combination) can be used to resolve network issues. A number of iterations will be required to assess combinations of mitigations to arrive at what low regret actions should be taken.

New network build solutions can be assessed for suitability using conventional network study tools, but non-build and hybrid build/non-build solutions need new cost assessment processes to be developed.

Both types of solution need to be compared using cost assessment techniques to understand which solutions are most economic to implement under certain scenarios.

<u>Summary of lessons learned and recommendations</u>

- New study tools for non-conventional build and non-network build techniques need to be developed to allow options to be assessed.

- The liquidity and cost of flexibility markets will define how applicable non-network build alternatives are, however replicable data for these markets can be difficult to coordinate. NOA tends to assume markets will deliver at an economic cost, however this assumption may not hold true for distriubution constraints, as these will be more locational specific

2.9 Undertake CBA for curtailment options

The transmission system typically concerns itself with flows across boundaries, to reduce the complexity of analysis. Distribution assets lying solely within a single transmission boundary zone will not have a greater whole system impact, with the exception being ANM systems or other curtailment mechanisms, which may affect the level of required transmission capacity should the curtailment requirements align.

When considering the CBA on a whole system basis, the boundaries being considered need to be defined as there will be a separate assessment required for each boundary.

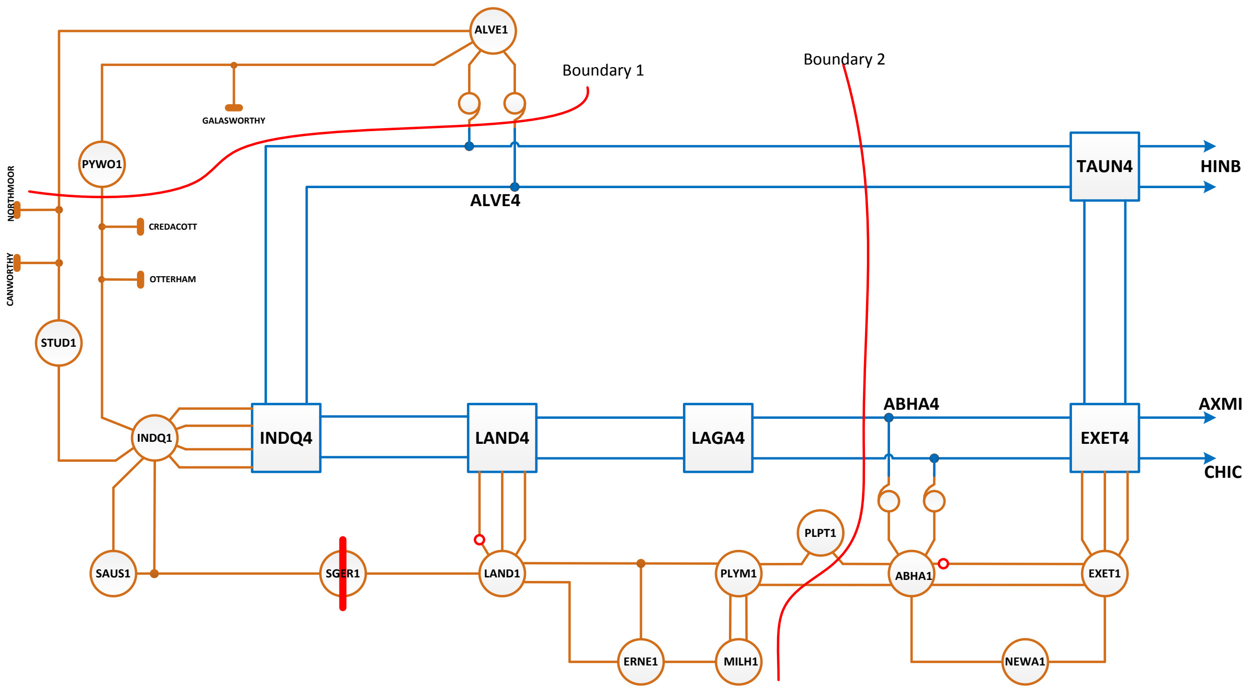

Figure 13 - an example of boundaries marked for whole system analysis

2.9.1 Distribution

The difference between the sum of all generation output of the Network Maximum Credible Loading Study and the Network Minimum Curtailment Study should provide the maximum requirement for generation curtailed. This can be combined with collated load duration information from the dominant generation source within the constraint area, to determine the likely number of half hours for which levels of generation dispatch above the network capacity may occur.

By integrating the area under the load duration curve, the total curtailment energy can be calculated. This is shown in yellow in the diagram below.

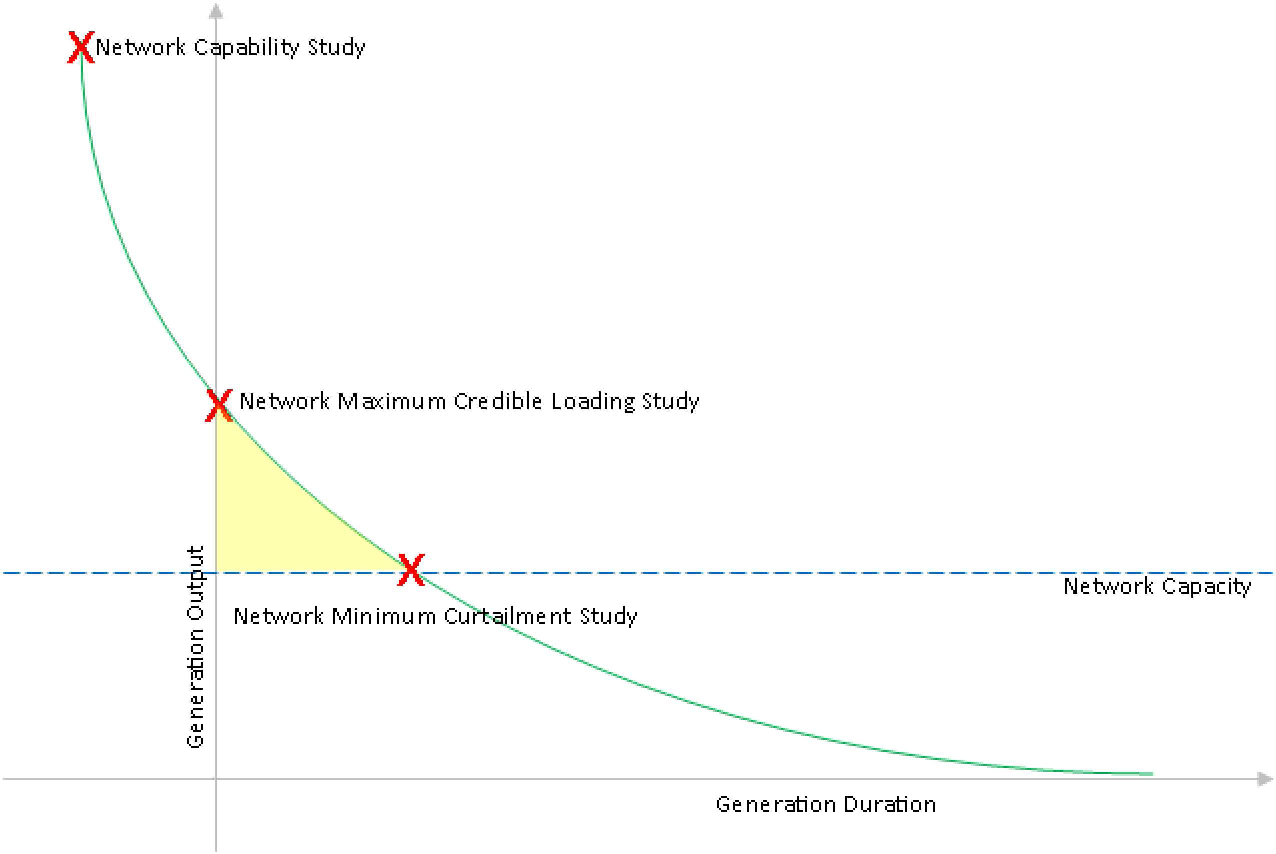

Figure 14 – Generation duration and intersection of edge case studies

For each constraint being considered, this analysis will need to be completed to determine the maximum overload under the condition being studied. If this process is completed on constraints using a bottom-up approach, then the required curtailment can be imposed on the nested constraints in the same manner, resulting in the solving of lower order constraints, either fully or partially resolving overarching constraints. This method ensures that curtailment derives the most benefit and is not double counted.

Once the volume of curtailment for the constraint has been calculated a price can be estimated using an indicative cost for curtailment of the lowest cost generation type running within the area when the constraints manifest. Care must be taken to ensure the curtailment of that generation type is able to fully resolve the constraint, else the costs of curtailing another generation type may have to be considered.

2.9.2 Transmission

To undertake a whole system options assessment, the process involves the following typical steps:

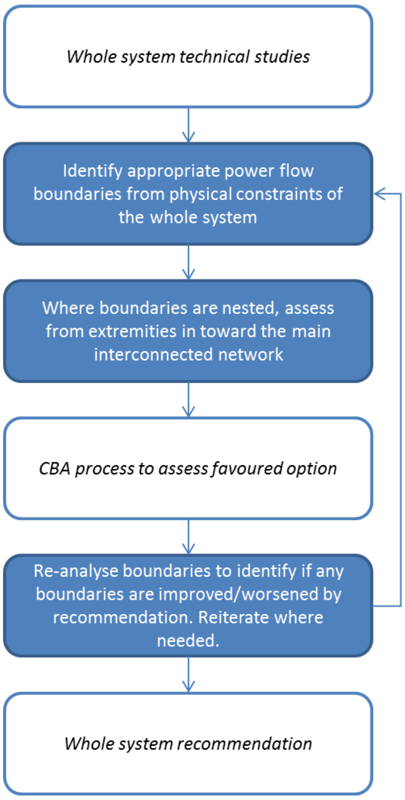

Figure 15 – Process involved in a Transmission CBA

The economic assessment of options can be carried out using a number of methods.

<u>Method 1: Finding breakeven cost from curtailment based on a load duration curve</u>

This method is typically used for smaller CBA's. A load duration curve for a generator (or pool of generators) is overlaid with a load limit to represent the maximum generation permitted by those generators. Anything above that line can be aggregated to give an estimated volume of generation which would need to be curtailed. Typically that generation would then be multiplied by a fixed price to indicate a level of cost to the system of respecting the constraint.

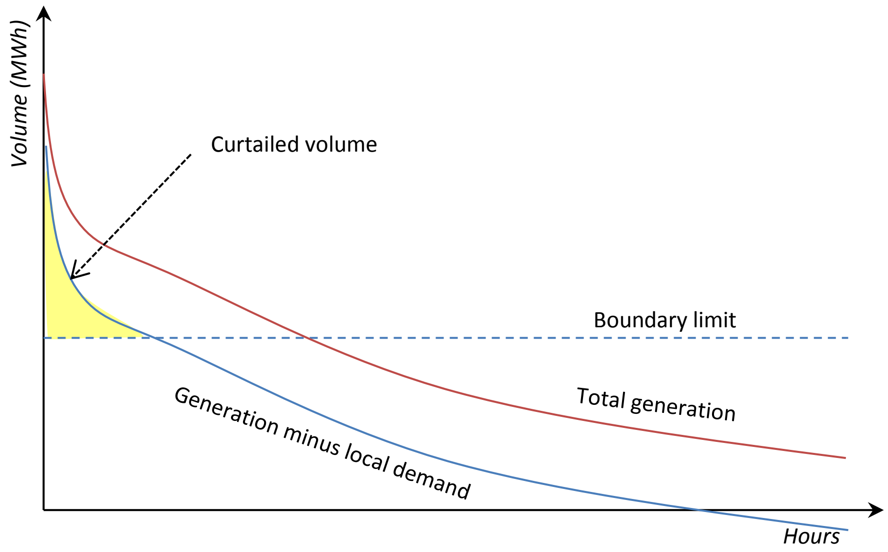

Figure 16 – Curtailment volume calculation

By identifying the volume which would be curtailed for different boundary limits, it is then possible to derive either a maximum cost for which any solution would have to fall under, or a breakeven constraint price, above which the option would no longer be economically justifiable. For example, if the annual curtailed volume were 1000MW per year, assume this occurs over a ten year period, would be a total of 10GW. If you then assume a £100/MW cost of curtailment you can calculate the cost of that curtailment as £1m. As such any investment costing less than £1m should be justifiable. If instead you didn't know the curtailment cost but knew a level of cost for the solution (assume £500k) you could then calculate a breakeven constraint price of £50/MW. From this you could make assumptions on the viability of any developments based on the likelihood of reaching those constraint prices.

The main drawback of this approach is that it can quickly become cumbersome when comparing multiple solutions and multiple scenarios, and is also subject to some fairly subjective assessments. The approach also doesn't consider wider system impacts, such as the replacement of the constrained generation and what other issues this might create. As such it is better suited for fairly isolated assessments where the problems and solutions are largely independent to the wider system, or where there is a large level of certainty on the scenario or prices.

Also this probably works when only considering a fairly consistent mix of renewable dominated generation. When you add significant volumes of controllable generation that responds to market conditions, then can't rely on history to predict future constraints.

Method 2: Scenario based constraint analysis with least worst regrets decision making

This method is used by the System Operator for wider system CBA's, including the Network Options Assessment. It involves performing a two stage optimisation of plant across the network with plant dispatched based on its short run marginal cost. The dispatch optimises to find the lower cost combination which meets the criteria of supply always meeting demand. The physical limitations of the system are then applied in the form of boundary limits between zones and the dispatch re-optimised, with plant being either bid off or offered on in order to respect the boundary limits of the network and to ensure demand is always met.

This optimisation is carried out for a variety of scenarios where the generation and demand can be changed, for different sensitivity conditions (e.g. weather), and for different options which typically manifest as boundary changes but could also take other forms which would impact the cost of redispatching. The benefit of each option is then calculated by finding the difference in constraint costs for the different options.

A Net Present Value (NPV) for each option and scenario is then calculated. This NPV includes: the amortised cost of delivering the solution, which is calculated using the Spackman Method to include the cost of finance and the social time preference rate for discounting; and the savings, also discounted at the social time preference rate to convert it to a present value and summed over an assumed window (typically the lifetime of the asset if an asset solution is being considered).

These NPV's are then compared and the regret of each is calculated for each scenario. The option which demonstrates the least worst regret across the scenarios is then recommended as the most economic.

This is sometimes backed up by further robustness tests in the form of sensitivities to key drivers such as capex and opex variations and breakeven analysis.

<u>Selected Method</u>

Step 1: Define a counterfactual case. This will be used as a base case to compare any additional costs or savings available when considering each of the possible options. Identifying benefits available when comparing to a counterfactual is often termed the Savings Approach. It is possible to perform a CBA without a counterfactual where you compare each option against each other and find the relative benefits or costs of each one.

Step 2: An economic modelling tool called BID3 is used to forecast the level of constraint for each of the options, following technical studies which determine the extent of constraint on the network and the extent that each option impacts the constraint.

Step 3: Find the Present Value (PV) of the cost (capex) of each of the options (provided by the proposer of the option) by applying the Spackman Method. This method involves amortising the cost of the investment, taking into consideration the cost of financing the investment at the Weighted Average Cost of Capital (WACC) for the company proposing to deliver the option. This finance adjusted capex is then discounted at the Social Time Preference Rate (STPR).

Step 4: Find the PV of the savings per option by first deducting the constraint costs of the counterfactual case from the option case to give a saving or cost for the option when compared to the counterfactual. Summing these savings over the life of the option and discounting the value by the STPR yields the PV of savings for each option.

Step 5: Find the Net Present Value (NPV) of each option by deducting the PV capex from the PV savings.

Step 6: Create a matrix of the NPV's across all of the options and scenarios modelled and then perform a Least Worst Regret analysis to identify the most economical option.

<u>Summary of lessons learned and recommendations</u>

- Estimating the volume of constrained energy from the calculation of the instantaneous exceedance of power at the constraint is possible by using load duration curves.
- This method will only work when considering a fairly consistent mix, dominated by non-dispatchable generation. When you add significant volumes of controllable generation that responds to market conditions, then can't rely on history to predict future constraints.
- More sophisticated tools which take into account market conditions across boundaries can be used to determine

2.10 Recommendations following CBA outputs

Once the CBA outputs have been completed for the non-build alternatives, these can be compared against other options which are also able to mitigate the identified issues and then the preferred options can be downselected.

By optimising the mixture of preferred options, a number of future recommendations can be derived, which implement a low regret path towards a better whole system outcome.

The underlying work beneath the recommendations can be revisited should the scenarios on which the study work is based, be fundamentally altered.

<u>Summary of lessons learned and recommendations</u>

- Regional and national assumptions that feed into scenarios should be reviewed and in future CBAs of this type assess the difference in regional and national capacities closely in order to identify a suitable range of credible scenarios.
- Further studies are performed by the NGSO to identify possible ways of scaling analysis completed within BID3 to more efficiently assess future CBAs of this type, particularly to refine processes for adjusting dispatch zones to match regional zones.

Appendix A – Worked example of NGESO CBA

For illustrative purposes only, below is a worked example of the general method above.

Table 1 -Example table of constraint costs for various options in a single scenario

Constraints (£m)	2018	2019	2020	2021	2022
Counterfactual	100	120	140	150	150
Option 1	80	80	90	100	100
Option 2	60	70	70	70	80
Option 3	50	60	70	70	70
Option 4	60	70	70	70	80
Option 5	90	100	120	130	130

Table 1 shows the constraint costs for a selection of options over a number of years. For simplicity in this example a lifetime of five years has been chosen. The constraint costs are calculated on an annual basis and the scenarios being analysed will respect capacity growth over years as well as any network developments assumed to be in the background for the cost benefit analysis (this typically includes the background assessed in the last NOA for transmission network boundaries).

Table 2- Example table of financed capex costs for various options

CAPEX (£m, incl. finance)	2018	2019	2020	2021	2022	*Total*
Option 1	1	1	1	1	1	*5*
Option 2	2	2	2	2	2	*10*
Option 3	5	5	5	5	5	*25*
Option 4	3	3	3	3	3	*15*
Option 5	4	4	4	4	4	*20*

Table 2 shows a table of amortised capex costs which include the cost of finance in the annual values.

Table 3- Example table of savings calculated from the constraint costs

Savings (£m)	2018	2019	2020	2021	2022
Option 1	20	40	50	50	50
Option 2	40	50	70	80	70
Option 3	50	60	70	80	80
Option 4	40	50	70	80	70
Option 5	10	20	20	20	20

Table 3 shows the savings available for each option. This is calculated by deducting the constraints of each option found in Table 1 from the counterfactual.

Table 4- Table of social time preference rates for a 2017 price base

Year	2018	2019	2020	2021	2022
STPR	0.97	0.93	0.90	0.87	0.84

Table 4 shows the relevant discount rates to be applied for each year. These are calculated by applying a compound discount rate of 3.5% per year. These rates are then applied to the annual values for capex and savings to yield the present values presented in Table 5 and Table 6 respectively below. Deducting the capex from Table 5 from the savings in Table 6 gives the Net Present Value for each option, as shown in Table 7.

Table 5- Example calculated present value of capex

PV of CAPEX (£m)	**2018**	**2019**	**2020**	**2021**	**2022**	***Total PV***
Option 1	0.97	0.93	0.90	0.87	0.84	*4.52*
Option 2	1.93	1.87	1.80	1.74	1.68	*9.03*
Option 3	4.83	4.67	4.51	4.36	4.21	*22.58*
Option 4	2.90	2.80	2.71	2.61	2.53	*13.55*
Option 5	3.86	3.73	3.61	3.49	3.37	*18.06*

Table 6- Example calculated present value of savings

PV of Savings (£m)	**2018**	**2019**	**2020**	**2021**	**2022**	***Total PV***
Option 1	19.32	37.34	45.10	43.57	42.10	*187.43*
Option 2	38.65	46.68	63.14	69.72	58.94	*277.11*
Option 3	48.31	56.01	63.14	69.72	67.36	*304.53*
Option 4	38.65	46.68	63.14	69.72	58.94	*277.11*
Option 5	9.66	18.67	18.04	17.43	16.84	*80.64*

Table 7- Example table of net present values for a single scenario

NPV (£m)	**Scenario 1**
Option 1	182.92
Option 2	268.08
Option 3	281.95

Option 4	263.57
Option 5	62.58

For illustrative purposes a number of additional scenarios have been added. In practice each scenario would have its own constraints and savings tables but the capex would typically be common for each option across scenarios (unless the scenario was a specific capex adjustment). The maximum NPV of each scenario has been highlighted in Table 8. This is used to produce the regrets in Table 9. As the NPV's represent the value that each option offers across each scenario, by subtracting the respective NPV from the maximum NPV for that scenario. This yields how much the consumer would regret (or the opportunity cost) if that option and scenario were to outturn in the future. If the best option for that scenario is chosen and that scenario outturns then the regret is zero as the best choice was made.

Table 8- Example NPV matrix for multiple scenarios and options

NPV (£m)	**Scenario 1**	**Scenario 2**	**Scenario 3**
Option 1	182.92	91.46	219.50
Option 2	268.08	134.04	321.70
Option 3	281.95	338.34	225.56
Option 4	263.57	395.35	237.21
Option 5	62.58	50.06	93.87

Table 9- Example regret matrix for multiple scenarios and options

Regret (£m)	**Scenario 1**	**Scenario 2**	**Scenario 3**
Option 1	99.04	303.89	102.20
Option 2	13.87	261.31	0.00
Option 3	0.00	57.01	96.14
Option 4	18.39	0.00	84.49
Option 5	219.37	345.29	227.83

Table 10- Example identification of the Least Worst Regret option

Regret (£m)	Scenario 1	Scenario 2	Scenario 3	Worst regret	
Option 1	99.04	303.89	102.20	303.89	
Option 2	13.87	261.31	0.00	261.31	
Option 3	0.00	57.01	96.14	96.14	
Option 4	18.39	0.00	84.49	84.49	Least Worst regret
Option 5	219.37	345.29	227.83	345.29	

Once the regrets have been calculated you next consider the worst regret provided by each option (i.e. the maximum looking across the options, as opposed to the scenarios). This informs you as to what the greatest opportunity cost is faced by selecting that option. The most economical recommendation is then the option that yields the lowest overall opportunity cost, or the least of the worst regrets. The Least Worst Regret method does have its limitations however it does provide a relatively conservative risk based decision making strategy. Other methods have been investigated however this method has been chosen as it provides a suitable level of protection for the GB consumer for network development considering the breadth uncertainties faced by the energy industry.