Main Interconnected Transmission System

Working Group 3 Progress Report

9 April 2010

Contents

1 Background

The Main Interconnected Transmission System (MITS) is defined within the SQSS as comprising all 400 and 275kV supergrid elements of the onshore Great Britain transmission system and, in Scotland, the 132kV elements of the onshore transmission system operated in parallel with the supergrid.

Working Group 3 (WG3) was established as part of the wider Fundamental Review of the SQSS to explore and report on:

- Whether the MITS operational and planning criteria and methodologies remain appropriate given wider industry developments,
- Options available for change; and
- The development of scenarios to demonstrate how each potential option might work in practice.

The working group's terms of reference involve investigating the following three broad interrelated areas…:

- Appropriate criteria and methodologies whereby Market Access signals may be converted into transmission capacity requirements;
- The use of cost benefit analyses; including consideration of the appropriate balance between operational and investment costs, sharing methodology (taking due account of the findings of the Transmission Access Review) and overrun (e.g. where a generator may exceed its share allocation); and
- Regional differences in criteria and methodologies (i.e. between the NGET, SPT and SHETL transmission systems).

…taking the following factors into consideration:

- The use of intertrip schemes to disconnect exports across interconnections with external systems;
- The contribution of different generation technologies (e.g. conventional, renewable and intermittent generation);
- The appropriate methodology for setting the year round background conditions against which the need for additional transmission capacity is judged in planning timescales to provide generation access to the MITS (e.g. exporting group).
- The treatment of large demand zones with little or no generation;
- The integration of offshore transmission networks;
- Methods for assessing options, including consideration of the: accuracy of results; complexity of applying proposed methodology; assumptions including reliability of data source; and the sensitivity of the results to data changes;
- The implications of the Transmission Access Review options for long term access rights and short term access rights;
- Treatment of potentially non-compliant parts of the GB transmission system during periods when short term access rights are applicable (i.e. where the transmission system is not designed to accommodate all short term access rights either bought or acquired through auction); and
- Criteria for assessing the consequences of any change proposal.

2 Existing MITS Operational and Planning Criteria

The SQSS criteria relating to the MITS is defined in Section 4 of the SQSS. Additionally, Section 4 makes reference to two appendices which are an integral part of this assessment, namely: Appendix C (Modelling of Planned Transfer); and Appendix D (Application of the Interconnection Allowance).

Appendix C describes the techniques which are used for modelling the planned transfer condition. The appendix describes how a peak demand generation scenario is built up and how account is taken of future generation patterns. It is this appendix which specifies a 20% plant margin for use in planning studies.

Appendix D describes how an allowance for security (i.e. the interconnection allowance) is calculated and added, in whole or in part, to transfers arising out of the planned transfer condition. This allowance is designed to take account of the expected variation in flows as a result of uncertainty in the demand and generation availability and merit order. In conjunction with the Appendix C the overall result is to deliver an acceptable Loss of Load Probability.

The SQSS allow design of the MITS to standards higher than those set out in section 4, provided the higher standards can be economically justified.

3 Working Group Progress

Given the working group's terms of reference, its initial focus was to develop methodologies and tools to enable the cost-effective balance between new transmission infrastructure, transmission-constraints, pre-fault preventive actions, and post-fault corrective actions covering different operating conditions (fair/adverse weather conditions, market prices, network reliability performance, etc) to be studied. Two different tools have been developed:

- The 'O+X' model identifies the transmission operating strategy that minimises the combined cost of unsupplied energy (X) and operating costs (O), including transmission constraints; reserve, response and intertripping (holding and expected utilisation) for a single MITS boundary.
- The 'DTIM' model, which optimises the balance of infrastructure and constraint costs over time and across multiple boundaries, using a simplified representation of the MITS.

The purpose, design, and limitations of each of these tools are explained in greater detail below.

Following their development, the tools have been used to study a range of different scenarios, with a view to identifying any clear implications for the optimal operation and design of the MITS. However, in view of the complex nature of the problem combined with uncertainty regarding appropriate values for a significant number of input parameters and the significant sensitivity of the results to variations in the input parameters, the working group has thus far experienced difficulty in drawing firm and generally-applicable conclusions from the analysis.

3.1. The Operation + Interruption Cost Optimisation Model (O + X)

3.1.1 Introduction

The ‘O+X’ model has been designed to allow WG3 to carry out economic and security studies related to transmission operating criteria in support of the GB SQSS Review. Important issues that can be investigated using O+X model are:

- utilising post-fault demand reduction/shedding and generator intertripping/reserves to facilitate higher pre-fault power transfers,
- evaluating and managing operational risk, e.g. the risk associated with faults that have failure rates which are affected by weather conditions,
- using generation and demand based grid support services to ensure system security during transmission outages,
- the impact of wind penetration in system costs and risks,
- the impact of market signals (fuel, bid, offer, and ancillary-service prices) on transmission operation.

In summary, the model simulates the operation of a single transmission system boundary and identifies the operating mode which minimises the overall cost of meeting response, reserve, intertripping, transmission constraints and unsupplied demand.

The model includes representations of the transmission circuits across the boundary and the associated fault rates of those circuits. In a similar fashion, the model includes typical fault rates for the generation on either side of the boundary. The model does not explicitly consider n-1 or n-2 security etc, but rather it considers the likelihood of various faults (including composite faults affecting two or more network components and/or generators) and the consequences associated with each fault.

The cost of constraints within each snapshot is calculated by initially determining the unconstrained dispatch of available generation (i.e. the minimum cost dispatch of available generation to meet the demand, ignoring the limitations of the transmission system), and then summing up the overall cost of the bids and offers which then need to be accepted to adjust the generation background so that the flows on the transmission network comply with the limitations of the network and provide a level of security which is associated with the risk of faults during the conditions represented by that snapshot. The net cost of accepting bids and offers for a snapshot is effectively the cost of constraints in that snapshot.

The costs of pre-fault actions are compared with the summed cost of possible post-fault actions multiplied by their respective probabilities. The O+X optimisation engine accepts bids, offers, intertrip holding, response holding and reserve holding in a manner which minimises the net cost of operation, i.e. the operating costs plus the likely load shedding, intertrip utilisation, and reserve utilisation costs, given the likelihood and consequence of contingencies in the each snapshot.

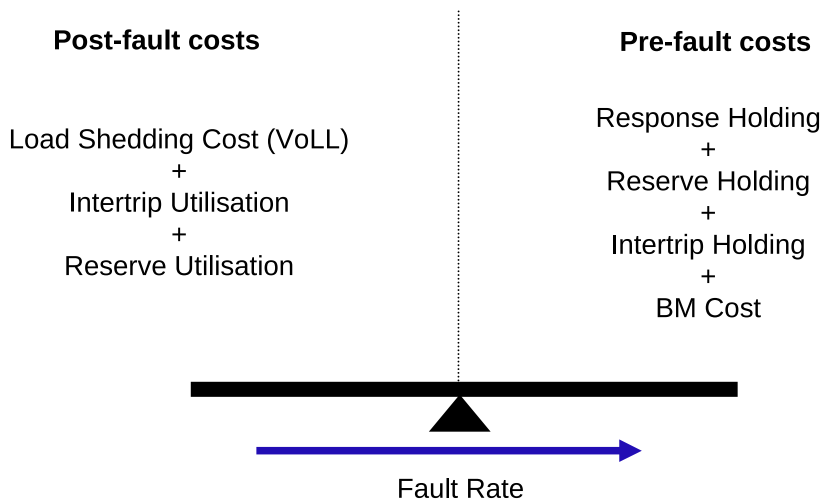

Figure 1 Pre & Post-Fault Costs

Although the O+X model analyses and optimises a single snapshot, the model can be used iteratively to analyse various snapshots and investigate how the optimum balance between costs varies in different operating circumstances. Using this iterative approach with various transmission capacities and configurations can provide insight into the merits of transmission reinforcement options.

Figure 2 shows for different weather conditions (with different fault rates) the theory of how different levels of power transfers through an existing transmission link are expected to influence the key cost components. Also, the efficient transfers that optimally balance cost of transmission constraints and expected unsupplied demand cost, among others, are shown.

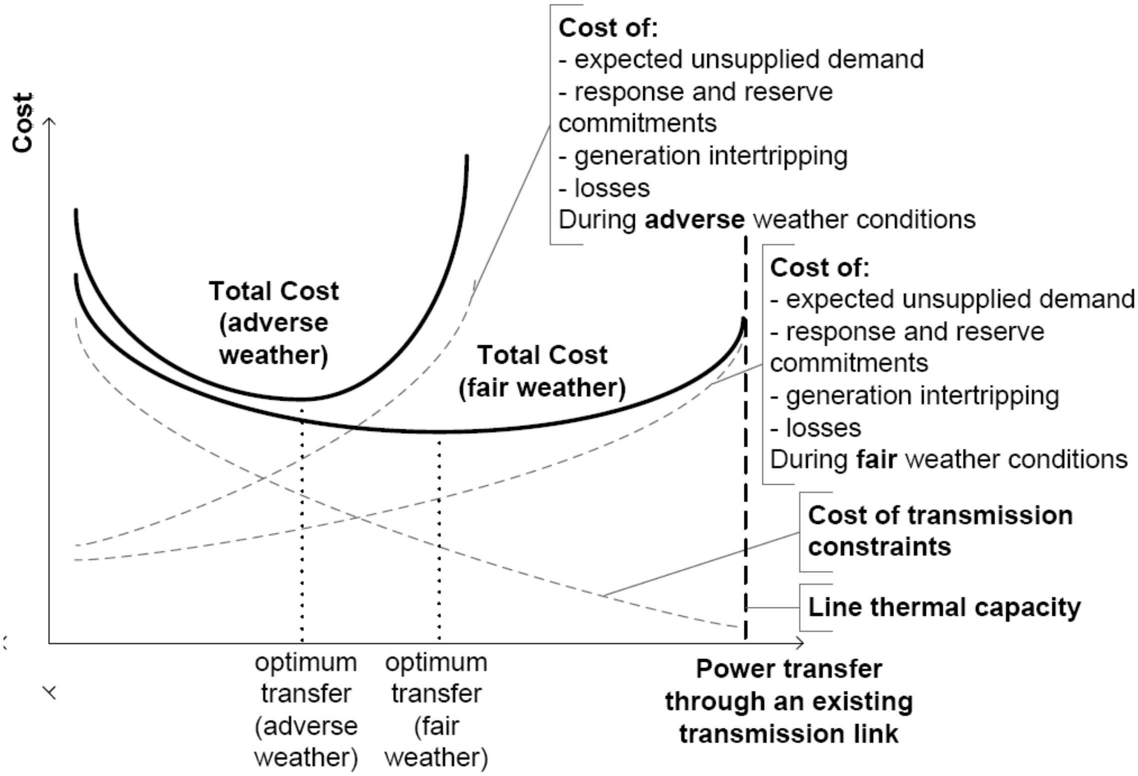

Figure 2 Indicative Variation of Key Cost Components with Weather Conditions

3.1.2 Functions

The model represents two nodes, each with generation and demand, separated by a transmission boundary. Inputs required by the model include:

- information about the generation at each node, for each of the twelve generation technologies considered by the model: the installed capacity, reliability, fuel price, bid/offer prices, and response and reserve capabilities along with their utilisation and holding prices,
- intertrip arming and utilisation fees together with potential constraints that represent their limited availability at each node,
- information about the transmission network between the two nodes: circuit availabilities, circuit loading characteristics, circuit forced outage probabilities in various weather conditions (including common mode), and pre fault, post fault short-term and post fault continuous line ratings,
- the magnitude of demand at each node and its Value of Lost Load (VoLL),
- further data to take account of the presence of DC links and non-optimum demand shedding.

Only one intact operating condition is analysed at the time. The analysis considers transmission failures (simultaneous independent and common mode outages) in combination with generation outages (single, double and triple per node) whilst also considering uncertainty in the power output from renewable generation. The first operating state is an intact system and this is coupled with all considered contingent states because the post fault generation re-dispatch must consider the intact system operation as an initial condition. Each analysed post fault condition is divided into two discrete time windows: one for fast automatic actions (e.g. response) and the second for slow manual actions (e.g. reserve). This allows the model to assess the progress of other variables whilst the re-dispatch actions are taking place after a fault occurs. Thus, for analysis of only one operating snapshot, many states have to be simultaneously considered in a coupled optimisation in order to identify the global optimum which drives the efficient power transfer through the boundary. Hence, the model analyses hundreds of potential post-fault operating conditions and requires a significant amount of computing power.

3.1.3 Interim Findings

There is general agreement within WG3 that the O+X model's elementary functionality is correct, and a significant amount of work has gone into using the model to study the sensitivity of operational costs to variations in the generation background, the value of VoLL, weather conditions, non-optimal load shedding, and assumed component downtime.

However, there is concern within WG3 that the presently fundamental nature of the O+X model makes it inappropriate to draw practical and generally-applicable conclusions from it at this stage. Factors believed to be material, but not yet considered in the model include:

- the simultaneous assessment of multiple boundaries (i.e. a basic representation of the network as an interconnected system)
- power system dynamic-stability, reliability, and implementation issues arising from the significantly increased use of the post-contingency shedding of generation and demand

Additionally, the O+X model is understandably sensitive to a large number of input parameters (e.g. bid and offer prices, cost of reserve and response services, value of lost load, generation and network fault rates). Some of these parameters could be determined in different ways, and as yet, no clear consensus has been reached regarding how this should be done.

In many ways the difficulties encountered with the O+X model illustrate the complex nature of power systems, with the interaction of many different economic and technical considerations. Nevertheless, it is hoped that with time these issues will be resolved and the O+X model can be used to provide insight and direction to the optimal operation, and ultimately design, of the transmission system.

3.2. The Dynamic Transmission Investment Model (DTIM)

3.2.1 Introduction

The Dynamic Transmission Investment Model (DTIM) works by evaluating the cost of operational constraints and comparing this with the specified costs of network reinforcement to identify the balance between the two which minimises the overall cost of power system operation and expansion over a given duration (e.g. the next twenty years). Based on this, the DTIM model indicates the optimal capability of transmission boundaries over time corresponding to this optimal balance condition.

Hence, DTIM allows users to carry out a number of economic studies related to transmission investment and congestion in support of the GB SQSS Review. Important issues that can be investigated using DTIM are the:

- appropriate balance between operational and investment costs, i.e. levels of transmission investment and constraints that lead to efficient system design,
- efficient timing of new transmission assets,
- the impact of renewable generation intermittency on the need for transmission investment,
- effects of different year round background conditions on constraints and investment modelling
- the effect of seasonal and dynamic line ratings, and circuit availability on the market and the need for new transmission infrastructure,
- impact of market signals (bid and offer prices) on investment requirements,

3.2.2 Data Structures/Inputs

Although DTIM's optimising engine minimises the overall costs of constraints and new infrastructure during the entire planning duration, it has five subsets of the overall planning duration (e.g. five year blocks) referred to as 'epochs' during which:

- different inputs can be specified (e.g. to account of variations in fuel costs or the construction of wind generation over time)
- DTIM can 'build' new transmission infrastructure (i.e. transmission infrastructure can only be 'built' at the start of an epoch – once constructed, transmission infrastructure is assumed to persist indefinitely)

DTIM estimates the constraint costs likely to be incurred within an epoch by further breaking down each epoch into 510 snapshots representing the range of background conditions that will likely be observed during the epoch. Each snapshot has an expected duration, which is associated with the relative likelihood of that condition. The overall cost of constraints can therefore be determined by multiplying the constraint cost identified for each snapshot by the snapshot's duration, and aggregating the results for all 510 snapshots. The relationship between the planning duration, epochs and snapshots objects is illustrated in Figure 3 below.

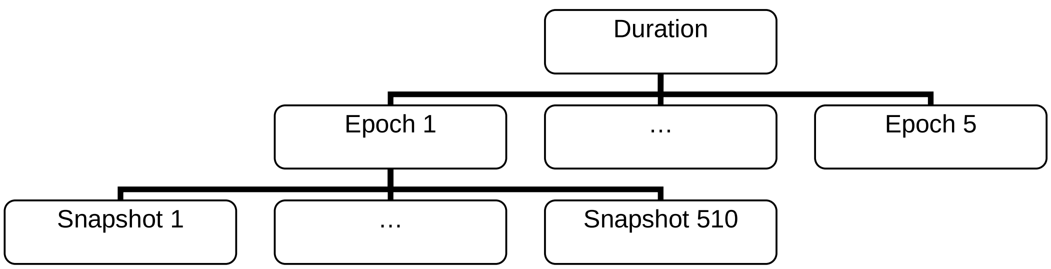

Figure 3 Time Series Data Structure

The 510 snapshots are obtained by combining 51 different demand levels with a 10-level wind output profile. Of the 51 demand levels, one of them is winter peak demand level, and the rest 50 are derived from a 5-level daily demand profile applying on 10 representative days. The 10 representative days are a working day and a weekend day during each of winter, spring, summer, autumn and the line maintenance season. In addition, the line maintenance days can represent the demand levels of any season specified by the user. The build-up of the 510 snapshots is illustrated in Figure below.

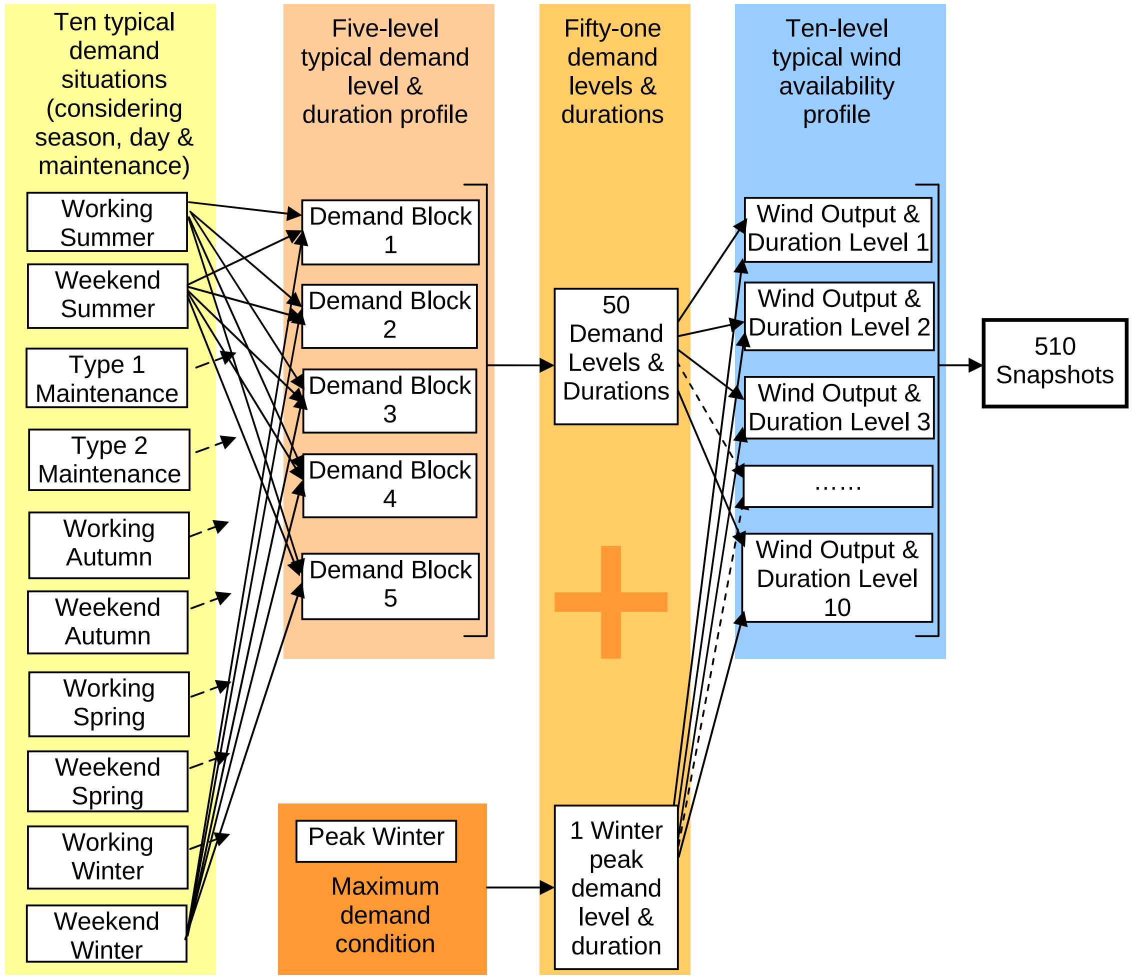

Figure 4 Composition of Snapshots within Each Epoch

The condition represented by each snapshot is then applied to a simplified representation of Great Britain's transmission system, and the cost of constraints in that condition is determined. The cost of constraints within each snapshot is calculated by initially determining the unconstrained dispatch of available generation (i.e. the minimum cost dispatch of available generation to meet the demand, ignoring the limitations of the transmission system), and then summing up the overall cost of the bids and offers which then need to be accepted to adjust the generation background so that the flows on the transmission network comply with the limitations of the network. The net cost of accepting bids and offers for a snapshot is effectively the cost of constraints in that snapshot. DTIM's optimisation engine accepts bids and offers in a manner which minimises the cost of constraints in each snapshot.

The GB MITS is represented in DTIM by a 16-node, 15-branch radial network, as depicted in Figure 5 below. Each node represents a zone, and each branch represents a boundary. A more detailed representation of the network is possible, but was not pursued given WG3's initial focus on investigating the principles of an efficient transmission network, and the additional computational burden that a more detailed representation would add.

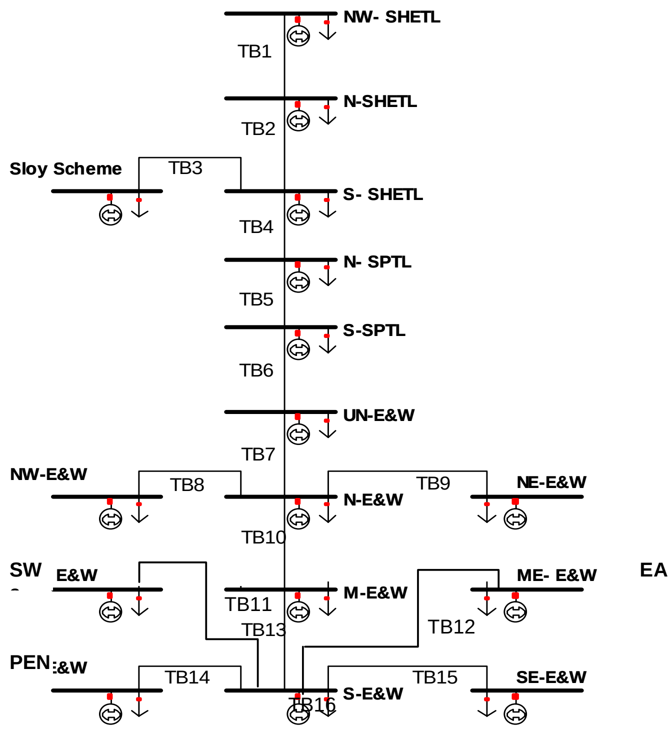

Figure 5 DTIM Network Topology

As part of the set of input data, twelve generic generators are assumed to be attached to each node, representing the twelve different generation technologies considered by DTIM. The availabilities of each generator technology are also user-inputs to the model together with wind generation, for which a 10-level output distribution is included as part of the set of input data. The fuel price, bid/offer price and installed capacity for each generation technology at each node for each epoch are also required by the DTIM model.

Each branch represents a boundary on the national electricity transmission system.

- Branches TB1 to TB6 equate to SYS boundaries 1-6.
- Branch TB7 is mapped to a non-SYS boundary, known as B7a, which runs South-of-Penwortham rather than South-of-Harker. Correspondingly, zone 7 expands to include NGET FLOP zones Q and R.
- Branch TB8 is a non-SYS boundary to North Wales, namely West of Deeside and West of Treuddyn.
- Branch TB9 is mapped to the Humber Estuary boundary, namely East-of-Keadby.
- Branches TB10, TB13 and TB15 are SYS boundaries B8, B9 and B15 respectively.
- Branch TB11 is south Wales boundary, namely West-of-Walham plus West-of-Melksham.
- Branch TB12 can be mapped to East Anglia.
- Branch TB14 maps to the boundary to Cornwall, Devon and Somerset (NGET FLOP zones F and E).

For each boundary the length (in km), initial transmission network capability (in MW) and the cost of building reinforcements to provide additional capability (in £/MW/km) must be specified. The transmission capacity expansion cost is a piece-wise linear function (i.e. £ per MW of additional capacity, per km of branch length) which can be specified in up to 5 five tiers (e.g. £1200/MW/km for the first additional 500MW of capacity, then £1,650,000/MW/km for the next 1MW, and then £0/MW/km for the next 1.8GW) to reflect the different reinforcements available to provide additional capability. The capital cost of new transmission infrastructure is annuitised at a discount rate supplied by the user. The ratings of boundaries are scaled by different factors corresponding to the five seasons (Summer, Autumn, Winter, Spring and Maintenance) and windy/non-windy conditions.

3.2.3 Functions

DTIM works by calculating the cost of operational constraints and comparing this with the specified cost of building transmission reinforcements to increase boundary capabilities, and thus identifying the balance between the two which minimises the overall cost of power system operation and expansion over the entire planning duration.

The objective function to be solved by DTIM's optimising engine is the overall combined cost of constructing transmission infrastructure and operating the power system over the entire planning duration. The optimisation constraints include: energy balance, boundary capability over various snapshots, generation capacity, offer/bid amount and network expansion effect (i.e. boundary capabilities of the present epoch = boundary capabilities of last epoch + extra capacity added in this epoch), among others.

The total objective cost and most of the constraints can be divided into sub-groups by years, but the network expansion effects are inter-temporal constraints, and therefore the overall optimisation model cannot be separated into sub-groups to obtain the global optimisation. Therefore, DTIM requires a large amount of computational memory to handle the optimisation problem. DTIM's input data processing and calculation functions are illustrated in Figure below.

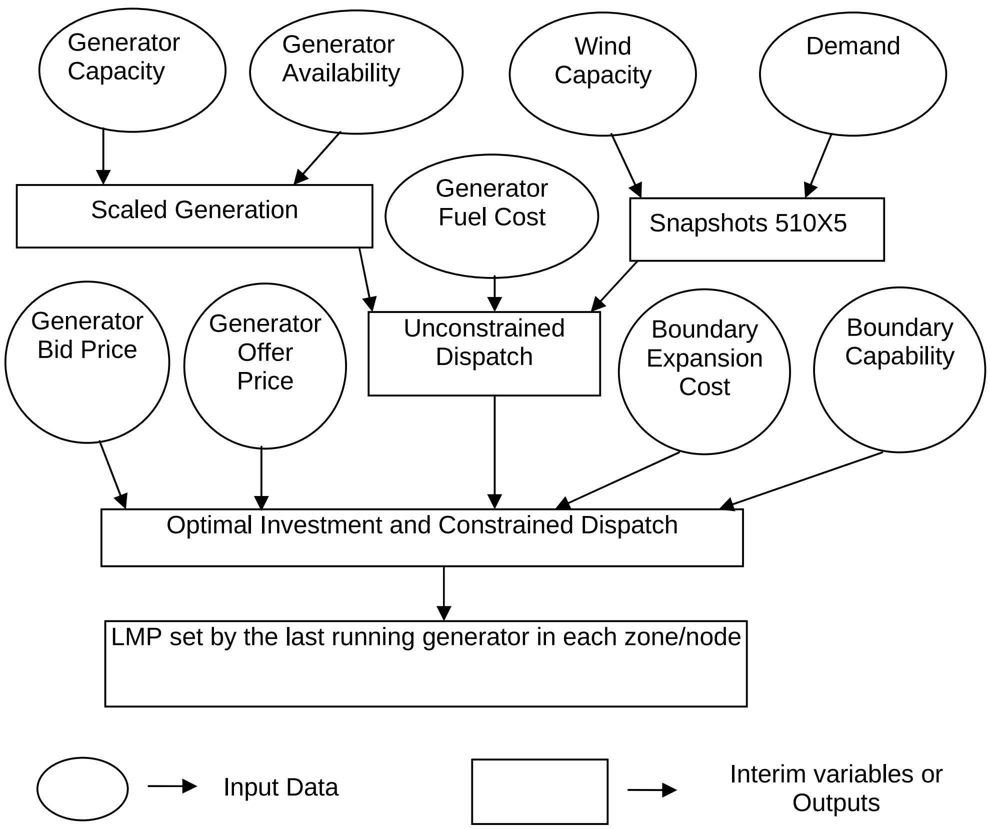

Figure 6 DTIM Data Process and Calculation

The principle outputs of one run of DTIM include:

- The build of new transmission infrastructure, represented as an increase in boundary capability by epoch
- The cost of the new transmission build, plus the costs of remaining constraints incurred on the system, both by epoch
- A breakdown of the constraint volumes and costs by generation technology and node
- Volumes of unconstrained and constrained generation running, by epoch and generation technology

- Locational Marginal Prices (LMPs) by node and epoch

3.2.4 Recognised Limitations

The availability profile of wind generation is assumed to be identical for all the wind farms across Great Britain (i.e. no regional variation is considered). For MITS planning purposes, assuming that wind speeds at all wind farms are fully correlated is considered optimistic. On the other hand, introducing regional wind speed variations would significantly increase the size of the optimisation problem. Given the highly correlated real wind profiles in GB and WG3's initial emphasis on investigating the principles of efficient network design, modelling a single wind profile, fully correlated throughout GB, was agreed to be a reasonable starting assumption.

DTIM uses a deterministic model of conventional generation (e.g. all gas/coal scaled to 90/85% availability for winter). As network constraints are highly sensitive to generation locations, modelling generators as partly-loaded units all running at the same time is a noteworthy limitation. A more suitable approach might be to use a Monte Carlo technique to randomly determine the availability (i.e. available or unavailable) of each generator using the specified average availability of the generator, repeating the analysis a sufficient number of times for statistical confidence to be reached, and then performing the optimisation based on the combined results from all of the cases studied. However, such an approach would likely increase the computational complexity by several orders of magnitude.

3.2.5 Interim Findings

There is general consensus within WG3 that the DTIM model is sound, and it has been found to produce results which are comparable with other cost-benefit analysis tools already in use. However, as with all cost-benefit analyses, the results DTIM produces are highly sensitive to the input parameters supplied to it. The acceptance of DTIM results therefore depends much more on acceptance of the parameters input into the model, rather than the model itself.

There is ongoing debate about some of the parameters required by DTIM - especially regarding the assumed value of bids and offers. The debate is due to the very significant discrepancy between the value of bids and offers that might theoretically be expected in a 'perfect market' (i.e. the marginal fuel cost), and what has been observed in practice. Whilst the elevated market prices are 'unexpected', they are none-the-less real, being passed onto market participants and ultimately consumers. The appropriate value to use when assessing the need case for long lead-time infrastructure with an economic lifetime of ~40 years depends on whether the higher-than-expected costs are a temporary irregularity that will fade away with time, or a practical reality in a 'real-world' finite electricity market.

More detailed analysis would need to be undertaken to quantify the financial risk to consumers associated with the over or under-investment in transmission infrastructure. On one hand, once transmission infrastructure is developed the cost of the infrastructure will continue to be incurred throughout its financial lifetime. On the other hand, analysis has shown that should reinforcements not be pursued and market-prices continue near their present level, the overall cost incurred by consumers would far exceed what the cost of additional transmission infrastructure would have been. Were constraint prices to increase as higher volumes of renewable generation connect to the system (significantly increasing the plant margin), the cost to consumers would be higher still. In this case, the decision could subsequently be taken to invest in additional transmission infrastructure, but high constraint costs would continue to be incurred throughout the years needed to design, consent, and develop the infrastructure. A thorough analysis and quantification of these issues could help to inform the discussion regarding the appropriate values to feed into a DTIM cost-benefit analysis. However, the weighting given to the different results would again come down to the perceived likelihood of bid & offer prices decreasing with time.

4 Other Work Considered

The Working Group, along with other parties, were much perplexed by the issue of the interaction of the SQSS and the Transmission Access Review. Expressed simply, the issue is a 'chicken and egg' question:

a. Does the SQSS take precedence, in that the SQSS determines a level of generation capacity that it is permissible to connect at a given location given any particular level of transmission?
b. Or does TAR take precedence, in that TAR coupled with User choices determine a level of generation capacity; and SQSS then has to translate this into a required level of transmission?

Broadly, the Working Group eventually concluded that the answer to this question is 'b'; and this is consistent with the emerging decisions from DECC that 'Connect and Manage' is the chosen way forward for TAR. But this conclusion was by no means obvious to the Working Group, or for that matter to other parties.

Moreover, because the treatment of TAR short-term access products (refer to CAP161 CAP162 and CAP163) has become stalled during TAR, at the time of writing (April 2010) the Working Group have not been able to consider how (if at all) any such short-term access products should be considered within the SQSS.

The Working Group performed some analysis, which started to deepen the results of GSR001 on the fraction of wind capacity that should be used in the framework SQSS Appendices C and D that set a Planned Transfer condition. These results are not reported here, but will be included in the work of a new SQSS working-group which is (in effect) reopening GSR001 during summer 2010.

WG3 intermittently debated the issue of the relative strengths and weaknesses of the current primarily deterministic approach of the SQSS chapter 4, and more wholesale adoption of a cost-benefit approach. As evidenced by the above discussion of O+X and DTIM, the issue rapidly became mired by debates over cost-benefit input data values, and whether it is even possible to agree values for use in appraising new transmission build, and no conclusions were agreed.

5 Further Work

Due to the complex and interactive nature of the issues WG3 has been investigating, its findings to date have been limited. However, the development of the O+X and DTIM models provide a basis for ongoing investigation. If given adequate time to fully investigate the issues and understand the implications of novel proposals, it is expected that this line of research will be fundamental to defining the long-term arrangements which be used to plan and operate the national transmission system.

Therefore, whilst WG3 will formally be concluded along with the rest of the SQSS Fundamental Review, the group recommends establishing an ongoing programme of assessment to continue on from where WG3 has left off.