Technical aspects of the Grid Investment Test

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***Abstract*—The Grid Investment Test (GIT) is an economic test used to assess the net benefit of transmission investments. It is used by Transpower for proposed investments in the Grid Upgrade Plan (GUP) and also by the Electricity Commission in reviewing and approving investments in the grid.**

The Government, through the New Zealand Energy Strategy, has set a target of 90% of new electrical generation to be developed from primary renewable sources by 2025. In response to this, and to help address concerns raised by industry participants, (particularly generators), the Commission initiated a project titled *"Transmission to Enable Renewables (TTER)"*.

The TTER project has essentially been divided into two parts. The first part has identified geographic areas where future renewable generation opportunities may be developed. In particular it has identified large amounts of wind potential, along with future geothermal and possible large hydro opportunities. The second part of the TTER project has been to identify remote areas where transmission constraints, or lack of any transmission at all, may limit future renewable generation development[1]. How the Part F rule framework may apply in such circumstances and the technicalities involved are the main focus of this paper.

I. Introduction

Continued development of large amounts of wind generation is causing concern among generating companies who may be subjected to constraints during certain system operating conditions. A good example of this is in the Lower South Island where a number of new wind projects may cause transmission constraints to occur on the existing transmission system.

The recent TTER project initiated by the Electricity Commission has identified enormous amounts of potential wind generation throughout New Zealand[2]. Regions with a high wind resource include the Wairarapa – Manawatu, the bottom of the South Island and also the very top of the North Island where a significant amount of Tranche 2 and 3 wind resource has been identified. These are all regions where significant transmission investment may be required to enable access to the potential resource.

In comparison with transmission to supply demand, transmission to enable generation is not as mature and has had less exposure under the current regulated arrangements. Some generators are concerned about the Part F rule framework and its ability to enable transmission investments for the purposes of building generation.

This paper examines the technical analysis techniques required to perform the Grid Investment Test (GIT). The first part of the paper examines analysis techniques for transmission into demand regions, both in the *core* and *non core grid*[3]. These techniques are generally well understood and have been applied by Transpower and the Commission[4] on several Grid Upgrade Plans [1].

The second part of the paper addresses analysis techniques for transmission projects that enable generation. This type of analysis is technically more complex.

II. Grid Investment Test Analysis

Figure 1 shows the different types of GIT analysis. Essentially the analysis is dependent on whether the transmission investment is on the *core grid* and whether the investment is to supply demand, i.e., peak winter demand, or to enable generation. In all cases, a Grid Investment Test is used to

[1]The TTER project is also (at the time of writing) investigating the co–optimisation of future generation build scenarios, taking into account the cost of transmission network augmentation using the Commission's Generation Expansion Model (GEM) http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html.

[2]Three Tranches of wind generation have been identified. 14GW of Tranche 1, with a capacity factor of 40%, another 14 GW (42420 GWh) of Tranche 2 at 35%, and 13GW (12990 GWh) of Tranche 3 at 30% capacity factor. Only the Tranche 1 wind resource, (and some Tranche 2 wind in the top of the North Island) has been used as input into the TTER study. http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/Economic-Wind-Resource-Study.pdf.

[3]The *core grid* was defined by the Commission, after consultation, and introduced as part of the EGRs by the end of 2005. It enables a two–limbed Grid Reliability Standard (GRS); effectively consisting of an economic standard for the *whole grid*, underpinned by a *safety net* of an N–1 standard on the *core grid*, *see*, http://www.electricitycommission.govt.nz/opdev/transmis/gridreliability.

[4]This paper provides an explanation of various analytic techniques that can be of use when considering transmission investment. The paper does not represent a decision of the Electricity Commission in respect of any specific investment or necessarily represent policies, views or approaches adopted or held by the Electricity Commission. The examples provided are for illustrative purposes only.

identify the least cost solution among multiple options[5].

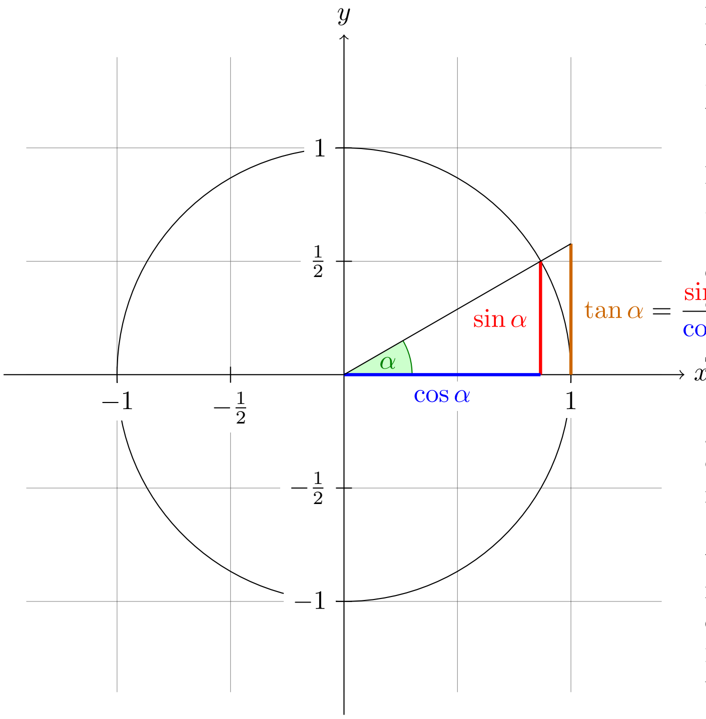

Fig. 1: Different types of GIT analysis for individual options - *simplified*

Generally GIT analysis can be split into two parts. Firstly, probabilistic techniques are used to determine the likelihood, or risk, of Expected Unserved Energy (EUE) or wasted energy (spill) among the different options. Then, an economic discounted cash flow analysis is used to convert EUE or spill to a present value for addition to other costs (e.g., capital costs, cost of electrical losses, fuel costs, O&M costs, etc). This is then repeated over a set of different alternatives and forecast into the future to determine the best overall economic investment path[6].

The only divergence from this generalised method is for *core grid* investments which effectively have a deterministic N–1 safety net, as shown in Figure 1. In these cases, EUE and spill are generally less of a concern but can still be included when assessing the cost of an investment option[7]. Power Systems Analysis (PSA) generally tends to dominate the analysis between different options to help determine the best overall economic solution.

For all GIT investment decisions it is important that there is an economic trade off. No system is perfect and all physical systems will have some theoretical level of EUE. Therefore comparing the cost of predicted future EUE with the cost of avoidance is one way of performing the GIT.

[5]Figure 1 is a simplification, intended to identify the major components of the GIT analysis. There are some investments which have combinations of each type of analysis.

[6]The costs and effects of uncommitted projects consistent with the future investment path are included as *modelled projects*.

[7]Especially relevant for non–transmission options.

One approach in achieving this is to use historic transmission power flow data to determine the existing transmission loading characteristics, such as the historic Transmission Duration Curve (TDC). Demand forecasts and generation scenarios as set out in the Grid Planning Assumptions (GPAs) are then used to predict the future transmission characteristics (the future TDC)[8]. PSA is used to determine transmission limits for each option, and probabilistic rates of generation and transmission outage are used to calculate the EUE.

For example, one option may be to do nothing, where the capital costs are zero but the EUE costs high, versus another option which may have significant transmission investment where the capital costs are high but the EUE costs low. This type of analysis is generally used for transmission to supply demand but can also be used for transmission to enable generation by investigating wasted energy such as spill, instead of EUE. An advantage of using a probabilistic approach is that intermittent generation such as wind can be handled easily.

With any transmission investment, PSA is critical in identifying the transmission constraints for each option. Transmission constraints can vary with the system condition and contingency, therefore limits can be required at N, N–1, N–2,... levels and for each different contingency. These are then used to compute either the EUE or spill in the probabilistic analysis. With *core grid* investments, this information can assist in calculating how much to defer the timing of the next investment.

Demand and generation forecasts play an important role in this part of the analysis and these are often subject to sensitivity analysis (for example high, medium and low demand forecasts can be tested).

The second stage of any GIT involves the actual economic analysis. This is typically achieved through a standard Discounted Cash Flow (DCF) analysis. A DCF analysis for the GIT is a yearly analysis, forecasting into the future the costs and benefits associated with each transmission option. Included in the economic analysis are the cost of capital expenditure, the cost of EUE and losses (or the benefit in the case of options that reduce these) and factors such as operating and maintenance costs (including fuel costs). Evaluating all options side–by–side in a DCF enables the best overall least cost investment path to be determined. Factors such as discount rate, capital costs, and the cost of EUE are all important factors in considering the economics of such investments[9].

Another approach for GIT analysis, particularly for transmission investments to enable generation, could be market–based simulation. This approach attempts to simulate market behaviour given a set of power system operating conditions, using historic hydro inflow sequences, etc. However, problems can arise in the complexity of modelling. Not only can participant behaviour be hard to predict, but also the required time–step for analysis tends to be outside that required when

[8]Alterations to the standard GPAs are often made after more detailed analysis of any particular transmission investment.

[9]Each of these inputs comes with some uncertainty, and this must be realised, usually through sensitivity analysis.

considering intermittent type generation such as wind (weekly rather then half–hourly or less). Also, although historic hydro inflow sequences are known for the last half–century or more, the same can not be said for wind inflow sequences.

The following subsections explain in more detail the different types of probabilistic analysis techniques required in performing the GIT for each of the different transmission investments shown in Figure 1.

III. Transmission to supply demand

A. *Non core grid – probabilistic analysis*

Figure 2 illustrates the probabilistic method of analysis that is used in performing the GIT for each different transmission option or alternative on the *non core grid*. It can also be used for analysis to enable future generation. This is discussed further in Section IV.

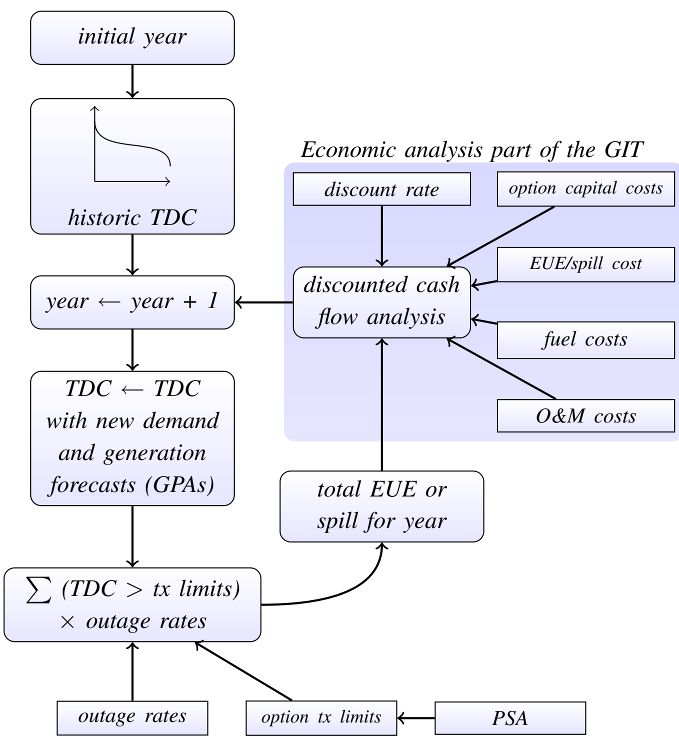

Fig. 2: Generalised GIT analysis procedure: *the probabilistic method*

For every transmission option and alternative considered in a *non core grid* GIT, EUE is priced at the Value of Lost Load (VoLL). Also included are electrical losses which can be significant. The historic TDC can either be calculated, given historic demand and generation time–series data, or, measured from recorded transmission power flow data. Depending on data availability, and assuming a simple radial system equivalent, this can be calculated for each time period in a historic year, i.e.,

$$transmission = demand + losses - generation \qquad (1)$$

where, each of the above variables are vectors of time–series data with common time integrity. If the generation time–series is uncertain then it is often best to subtract a low generation year, such as a dry year for hydro–based generating regions[10].

Once transmission time–series data are calculated (or measured), the TDC is found by sorting the time–series transmission vector to show the historic loading of the existing transmission system[11].

To determine future amounts of EUE, forecasts are used to multiply and/or provide step load increases to the demand[12]. Unless future generation within the demand region is certain, generation forecasts will often tend to err on the side of caution and assume no new generation builds. These inputs determine the estimated future TDC to be used in calculating the EUE for the particular year in question.

The TDC is then compared with the transmission limits for the option being considered. If the N–1 limits are less than any part of the TDC then there will be a higher risk of unserved energy. If the N limits are less than any part of the TDC then there will very likely be unserved energy. The amount of unserved energy is dependent on the probability of outage, the N and N–1 transmission limits, as well as the system operation immediately following a contingent event.

For example, an outage on a line could cause the loss of load to a whole region. This could occur in a voltage constrained region with no Special Protection Schemes (SPSs) or inter–trips in place.

Alternatively, SPS or inter–trips may be in place resulting in only a small amount of EUE. This is illustrated in Figures 3 and 4 with the grey areas in both figures showing the risk of unserved energy with and without some sort of SPS or inter–trip arrangement. An inter–trip arrangement would be designed to trip demand to the N–1 security transmission limit immediately following the contingent event[13]. Without the use of an SPS or inter–trip, a full power outage follows any contingent event, as illustrated in Figure 4.

In this instance the GIT could be used to economically justify the installation of demand reduction SPSs or inter–trips using the difference between the EUE both with and without the SPS system.

Once the forecast EUE is calculated, it is then converted into a dollar value for input into a DCF analysis for comparison among different options. Comparing the different options in the DCF will lead to a least cost development path, often being a combination of the different options themselves.

[10] Losses can often be estimated, dependent on demand and based on peak demand, ie, $Losses = k \times Demand^2$ where, $k = \frac{peak\ Losses}{(Peak\ Demand)^2}$. Peak demand and losses are found from a load flow solution.

[11] In New Zealand, half–hourly data for each Grid Exit Point and for all generators can be obtained from the Electricity Commission's Centralised Data Set (CDS) http://www.electricitycommission.govt.nz/opdev/modelling/centraliseddata/index.html.

[12] http://www.electricitycommission.govt.nz/opdev/modelling/demand/index.html.

[13] In some cases such schemes may be economic for N–2 contingencies, for example, loss of a large transmission line feeding Auckland.

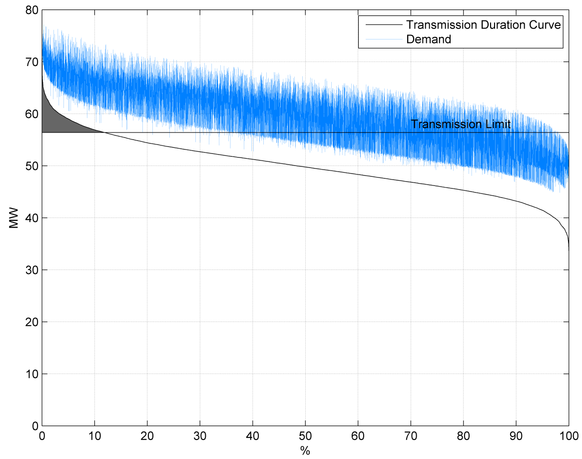

Fig. 3: Risk of EUE with SPS or inter–trip protection

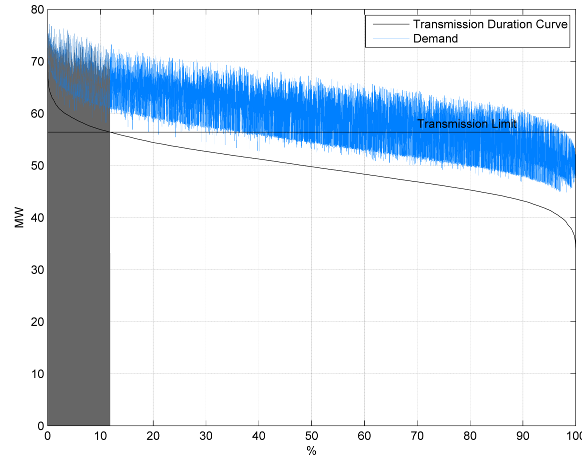

Fig. 4: Risk of EUE without SPS or inter–trip protection

For example, the following transmission options could be considered;

- Option 1 - Do nothing
- Option 2 - Thermal upgrades (line re–tensioning)
- Option 3 - Voltage support (Capacitor banks or dynamic reactive support (SVCs))
- Option 4 - Duplexing or reconductoring circuits (which may involve additional tower strengthening)
- Option 5 - Build a new line
- Option 6 - Addition of a peaking plant (such as diesel generators or pumped hydro storage)
- Option 7 - Demand management

Generation within the demand region can be an alternative to transmission investment, as in Option 6. In a GIT analysis, transmission options can be economically compared with generation and demand management options within the demand region[14].

In *non core grid* investments there can be two options for the required MW capacity of peaking plants. The first option is the cost to cover the worst case N–1 contingent event. The second option is the cost to cover demand above the N transmission limit. Both options can be considered alternatives; the first option will require more peaking plants, while the second option incurs EUE costs.

B. Core grid – Deterministic analysis

The *core grid* is defined in the EGRs by transmission links where an outage may cause the cascade failure of 150 MW or more into demand regions.

So far we have discussed the technicalities of the GIT on the *non core grid*, or transmission links of less than 150 MW into demand regions. Essentially, this same methodology could be used on the *core grid*, however, the safety net proposed in Part F of the EGRs requires all *core grid* transmission investments meet the N–1 criteria. This makes the analysis more deterministic than probabilistic and effectively reduces the N–1 EUE to zero[15].

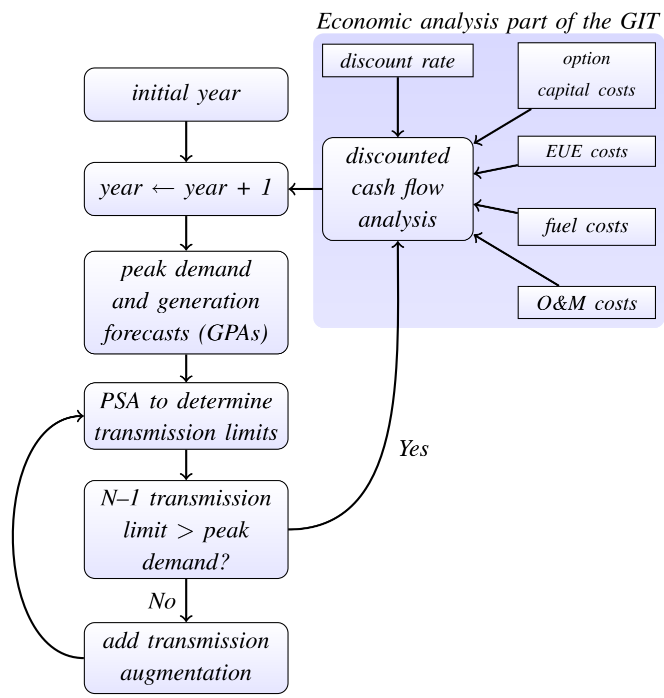

Fig. 5: Generalised GIT analysis procedure: *the deterministic method*

Core grid GIT analysis therefore tends to be more focused on the different transmission options, their capital cost, and in particular the PSA required to model their effect. Figure 2 can be redrawn to show the GIT analysis procedure that can be used for *core grid* transmission investments into demand

[14]When economically comparing fossil fuel generation, fuel inflation costs should be considered. A levelised bus–bar approach that takes into account fuel inflation costs can solve this issue [2].

[15]Depending on project type and size, N–2 or other high impact, low probability events may be included in the analysis.

regions (ignoring higher impact EUE events), as illustrated in Figure 5.

Recent Grid Upgrade Plans (GUPs) provided by Transpower to the Electricity Commission are in this category. For example, the North Island Grid Upgrade (NIGU) and the Otahuhu switch yard diversity project.

As discussed above, the GIT analysis for *core grid* transmission investments into demand regions tends to be dominated by the PSA between the different options. Technical aspects of the grid operation can become quite important. An example is discussed in the following section.

C. The effect of power factor in voltage constrained regions

An example of Power Factor improvement on transmission limits is illustrated in Figure 6. Power Factor improvement also improves losses in both the transmission and distribution systems. Both these factors could be considered as part of a *core grid* GIT analysis. In this example the power factor is varied from 0.98 (lagging) to unity in the demand region.

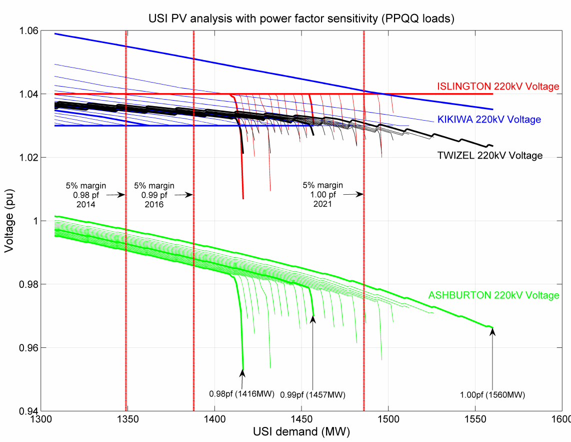

Fig. 6: Example showing the effect of improving power factor on voltage stability limits into the USI

The analysis is typical of voltage stability type analysis that must be performed in voltage constrained regions. Figure 6 is known as a Power–Voltage (PV) curve analysis. It plots voltage with increasing demand at certain bus–bars, throughout the USI network. The analysis is usually automated within a power flow program[16], by slowly increasing the demand in the USI while monitoring the voltage at certain buses. The extreme points on the right hand side are where voltage collapse occurs. This can be seen in the severe collapse of voltage (the many dropping lines) as the demand increases. From left to right, the vertical red lines show expected transmission limits for 0.98 (lagging), 0.99 (lagging) and 1.00 (unity) power factors. The analysis of Figure 6 is constant real and reactive power, i.e., as voltage drops the action of tap changing transformers attempt to keep power constant. It is therefore considered a long time–frame analysis, perhaps out to thirty or more seconds. Faster transient analysis is often required, however this is beyond the scope of this paper.

IV. Transmission to enable generation

Before detailing the TTER project, it is worthwhile discussing how the Part F rule framework may apply in enabling generation.

A. How the GIT applies

There is a fundamental difference between developing transmission to enable generation, and developing it to supply demand. Demand areas are fixed geographically and the options are generally either alternative transmission investment into the demand region, or, generation within the demand region. This is not so for transmission to enable generation. Unlike demand, generation plants, and particularly renewable generation plants such as wind generators, are geographically scattered across the country.

The GIT, being a least cost economic test, must consider all of these future generating possibilities as options. For example, there may be a cheap source of renewable generation a great distance from the demand that requires significant transmission investment to enable it. Conversely, there may be a more expensive generating plant closer to the demand region requiring no transmission investment. Which is the most economic option? How these options compare with one another is the focus of the GIT when used for approving transmission to enable generation. The difficulty arises in that there are many different options for future generation development making the analysis complex[17].

The probabilistic GIT analysis for each individual option can be reasonably straight forward in comparison if the simplified analysis of Figure 2 is used. Here the wasted energy (spill), could be priced at the marginal difference between high thermal and low renewable energy costs. Section IV-C demonstrates the application of the probabilistic GIT in enabling transmission investment in the Lower South Island.

B. The Transmission to Enable Renewables Project

The first part of the TTER project has identified geographic areas where future renewable generation opportunities may be developed. It has identified large amounts of wind potential, along with future geothermal and possible large hydro opportunities.

The most notable report, from consultants Connell Wagner[2], has used advanced mesoscale modelling and GIS techniques to identify huge amounts of feasible economic wind generation. Several key regions have been identified, including the very top of the North Island, the Manawatu-Wairarapa region, and the Lower South Island (LSI). These three regions have substantial wind generation that may require new or upgraded transmission capacity. Table I shows the results of Connell Wagner's wind resource study.

[16]Such as PSSE version 30.3.

[17]To complicate things further, factors such as the cost of losses and demand growth between regions may also play important roles when considering individual options.

TABLE I: Results of the Connell Wagner Wind Resource study - Tranche 1[a]

	Region	Capacity (MW)	Annual Energy (GWh)
1	Northland[b]	390	1379
2	Auckland[c]	30	110
3	Waikato	140	490
3a	Great Barrier Island	420	1470
4	Bay of Plenty	160	560
5	Taranaki	200	700
6	Taupo-Wanganui	560	1980
7	Hawkes Bay	1680	5890
8	Manawatu	3230	11320
9	Wellington	2100	7360
	North Island	**8910**	**31230**
10	Nelson-Marlborough	660	2310
11	West Coast	20	70
12	North Canterbury	1040	3640
13	South Canterbury	10	40
14	Otago	1200	4200
15	Southland	2580	9040
16	South Westland	0	0
17	Fiordland	70	250
	South Island	**5580**	**19550**
	New Zealand	**14490**	**50780**[d]

[a] Tranche 1 has an average capacity factor of 40%. Connell Wagner also identified 13800 MW (42000 GWh) of Tranche 2 at 35% and 13000 MW (34000 GWh) of Tranche 3 at 30% capacity factors.

[b] Northland also has 1620MW,4770GWh of Tranche 2 and 2570MW,6750GWh of Tranche 3 wind resource.

[c] Auckland also has 550MW,1690GWh of Tranche 2 and 950MW,2500GWh of Tranche 3 wind resource.

[d] For comparison, the total New Zealand GXP demand for the year 2007 was around 38000 GWh.

The second part of the TTER project is also (at the time of writing) investigating the co–optimisation of future generation build scenarios, taking into account the cost of transmission network augmentation using the Commissions Generation Expansion Model (GEM)[18]. The Commissions GEM model uses Mixed Integer Programming (MIP) optimisation software to determine the most economic future generation build scenarios. It considers many different costs but also includes the costs associated with transmission upgrades and transmission losses.

C. Example: probabilistic analysis for the LSI

The Lower South Island is constrained by three 220kV transmission circuits; Roxburgh – Clyde A & B, and the Roxburgh – Naseby – Livingstone circuit. The concern faced by generators is that renewable energy will be spilt more often due to the likely development of wind generation south of the transmission constraint. Although the LSI region is often an importer of power, at times of low demand and high generation from renewables the region exports power north. Currently, this region has a transmission constraint that limits this export of power. Although this constraint does not often bind, it may become a future problem due to the large increases of wind generation planned. Figure 7 shows the basic single line diagram of the transmission system.

[18]http://www.electricitycommission.govt.nz/opdev/modelling/gem/index.html

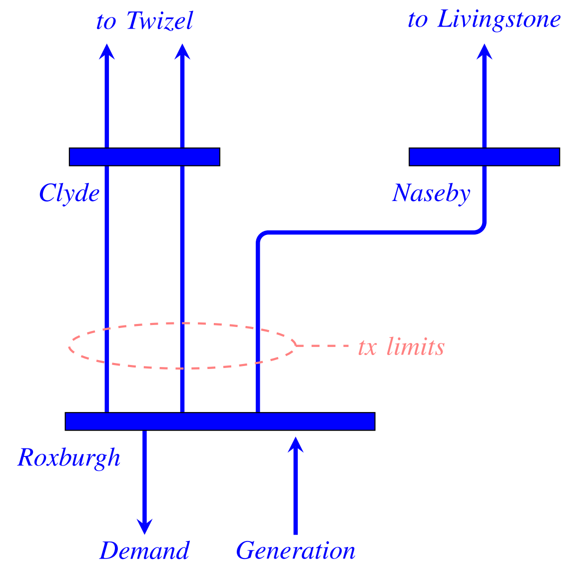

Fig. 7: Simplified Lower South Island system

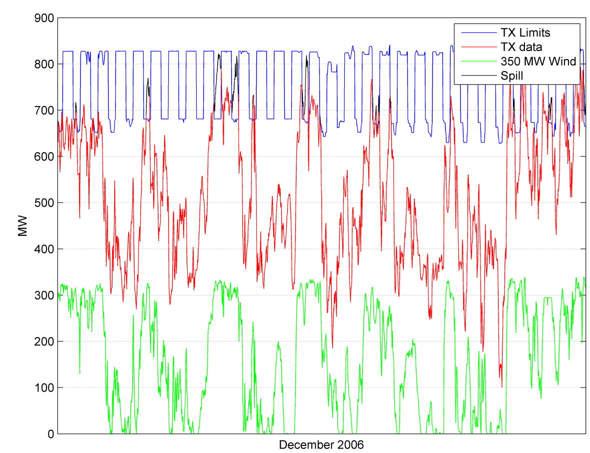

Fig. 8: Time–domain historic data example

Here, we can investigate the effect of future amounts of wind development by applying a probabilistic type grid analysis [3]. This is essentially the same analysis used for *non core grid* transmission investments, which calculates the probability of exceeding the transmission limits and pricing the wasted energy accordingly, i.e., Figure 2. The differences are that wasted energy is priced at the cost of spill, instead of the price of VoLL ($20,000), and in this case the half–hourly transmission into and out of the area can include the effects of wind by subtracting a vector of half–hourly wind data from the half–hourly demand data, as in equation 1. The TDC is then found by sorting the half–hourly transmission data. This analysis can then be repeated with increasing levels of wind

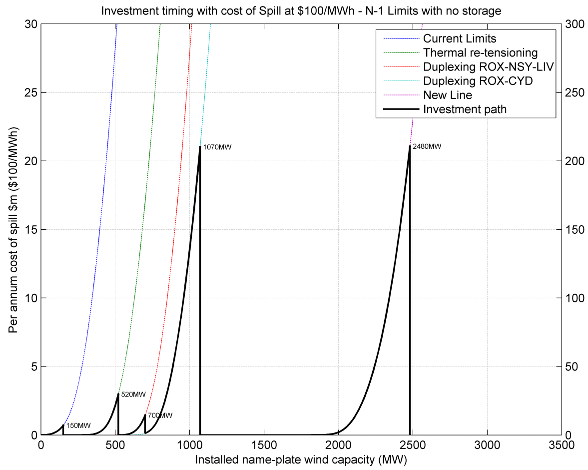

Fig. 9: Cost of energy spill, N–1 tx limits, no storage

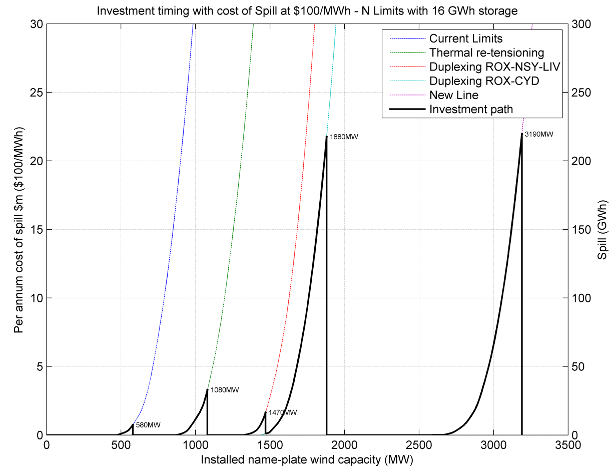

Fig. 10: Cost of energy spill, N tx limits, 16GWh storage

generation by scaling the half–hourly wind data.

For this example some complications arise. The first is the transmission limits, which are dependent on Clyde generation. The second is that many of the existing hydro plants, particularly Manapouri, are able to reduce generation and store water, essentially curtailing any spill. The problem then becomes more difficult.

Figure 8 shows historic time–domain data used in calculating spill with increased levels of wind generation in the LSI. The green data shows a scaled version of Te Apiti wind farm half–hourly data, essentially providing the wind characteristic for a 350MW sized farm in the LSI. The red line shows the historic transmission data calculated during December 2006 with the 350MW wind farm added. The blue lines show the transmission limits being dependent on winter, summer, and Clyde generation. When the power transmitted exceeds the transmission limits energy is either stored or spilt.

Figure 9 illustrates the results of such analysis with increasing levels of wind generation and with different transmission limits relating to different transmission investment options. The different options are; thermal upgrades ($6.3m) followed by duplexing on the ROX–NSY–LIV circuits ($29m), further duplexing on the ROX–CYD circuits ($14m) before a new line is required ($210m)[19]. The HVdc capacity may also limit export of energy from the South Island. This has not been modelled.

The y–axis shows the cost of spill, priced at $100/MWh. The black line represents a possible investment path dependent on the level of future installed wind generation. The black line assumes it is economic to upgrade to the next investment once the spill costs reach 10% of the capital investment costs of the following option. This is rather basic, but gives indicitive results.

The results of Figure 9 are worst–case results. No storage has been modelled and the transmission out of the region is assumed to be at the N–1 limit. However, implementing an SPS or inter–trip scheme enables the N limits to be used.

The model can be improved by implementing a storage regime. This has been achieved through manipulating the historic time–domain data to enable some storage, during previous spill periods, then exporting it north when the transmission constraint is relieved.

Figure 10 shows the improvement in the cost of spill by assuming N transmission limits with an SPS, generator runback scheme in place, 16 GWh of storage and with the assumption of $100/MWh as the marginal price between thermal and renewable.

Table II shows the substantial difference in results from the two figures.

TABLE II: TRANSMISSION CONSTRAINTS OUT OF THE LSI

	N–1, no storage, *(ref. fig. 9)* (MW)	N, 16GWh *(ref. fig. 10)* (MW)
Current limits	150	580
Thermal re–tensioning	520	1080
Duplex ROX–NSY–LIV	700	1470
Duplex ROX–CYD	1070	1880
New Line	2480	3190

V. CONCLUSION

This paper has addressed technical analysis techniques for performing the Grid Investment Test. It has reviewed the GIT for transmission investment into demand regions, explaining the probabilistic analysis method required for *non core grid* investments and the deterministic method of analysis required for *core grid* investments. Transmission to enable generation, in particular renewables, has been discussed with some of the technicalities and complexities of the analysis addressed. An

[19]These costs are approximate, based on building block cost estimates provided by Transpower http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/pdfsconsultation/renewables/TTER\%20report.pdf. Also, without a suitable wind generation forecast, this analysis did not use a DCF but assumed a crude Capital Recovery Factor (CRF) of 0.1 [2].

example in the Lower South Island has been used to investigate the probable cost of spill resulting from a constrained grid and increased levels of wind generation in the region.

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