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Report

MP198 Load Flow Modelling Service

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1 CONTENT

2 PROJECT OBJECTIVES AND INTRODUCTION

Siemens PTI (PTI) has been commissioned to assist ELEXON and P198 Modification Group in the assessment procedure of the BSC (Balancing and Settlement Code) Modification Proposal P198 ('Introduction of a Zonal Transmission Losses Scheme').

This section presents the key summary elements of the Modification Proposal P198 and presents the MP198 Load Flow Modelling Service objectives.

2.1 Modification Proposal P198 – key summary elements

MP P198 was raised on 16th December 2005 by RWE Npower ('the Proposer').

P198 seeks to allocate the costs of variable losses to Parties on a 'zonal' basis, according to the extent to which each Party gives rise to them. The solution proposed by P198 is based closely on Proposed Modification P82, and involves the following methodology for calculating non-zero TLFs:

- An electrical model of the Transmission System (a 'Load Flow Model') would be developed, containing 'nodes' to represent points where energy flows on or off the system. Each node would be allocated to a specific zone on the network. These TLF zones would be set by the Panel, based on the geographical areas covered by existing GSP Groups.
- Prior to the start of each BSC Year (1 April – 31 March), the Load Flow Model would be run by a TLF agent/service provider to calculate how a variation in generation or demand at each individual node would affect the total transmission losses from the Transmission System. This 'marginal' methodology would be applied using Metered Volumes and network data for sample Settlement Periods from a preceding 'reference' year. The output of the Load Flow Model would be a TLF value for each node in each of the sample Settlement Periods. Positive TLF values would be produced for nodes where an increase in generation (or reduction in demand) had the effect of decreasing total transmission losses. Negative TLF values would be produced for nodes where an increase in generation (or reduction in demand) had the effect of increasing total losses[1].
- These raw nodal TLFs would be averaged across all the nodes in each TLF zone by 'volume-weighted' averaging, to give a zonal TLF for each sample Settlement Period. These would then be converted to annual zonal TLFs by 'time-weighted' averaging.
- The annual zonal TLFs would be adjusted through a 'scaled marginal' methodology, using an appropriate scaling factor such that they represented only the variable element of transmission losses. These adjusted annual zonal TLFs would be endorsed by the Panel before being used in the TLM cost-recovery calculation for the applicable BSC Year. A positive TLF value would increase the value of TLM used to scale a BM Unit's Metered Volumes (a benefit to generators and disadvantage to Suppliers), whilst a negative TLF value would decrease the value of TLM (a benefit to Suppliers and disadvantage to generators).
- The remaining 'fixed' element of transmission losses would continue to be recovered under the Code's existing uniform calculation of TLMO+/-. The existing overall 45% production / 55% consumption allocation of total transmission losses would also be retained within the TLMO calculation.

1 This sign convention (opposite to what is obtained directly from the calculation method) was introduced for convenience in further calculations using the TLFs.

2.2 MP198 Load Flow Modelling Service objectives

Objective A - Calculation of TLFs. The Service Provider will generate TLFs; factors representing the change in transmission losses arising from marginal changes in demand or generation at nodes on the transmission network. TLFs will need to be generated under a range of specified scenarios. (Using the TLFs calculated by the Service Provider, TLMs will be calculated by ELEXON.)

Objective B – Estimation of Predictability & Stability of TLFs. The Service Provider will establish the sensitivity of TLFs to changes in demand and generation by both time and location. In addition, the variability of TLFs will need to be estimated for several time frames. The changes to be modelled will be specified under the scenarios made available to the Service Provider.

Objective C - Credible & Accurate Model. To ensure that the TLFs generated by the model are as accurate as possible, the model should accurately represent the physical characteristics of the GB transmission network. In addition, the input data should reflect the conditions prevailing on that network at the time in question. To ensure that the TLFs generated are credible, all assumptions used in the modelling should be credible, accurate and clearly described.

Objective D – Transparent Model. To ensure maximum transparency of the modelling undertaken, the operation of the model and all input data must be objectively derived from public sources (or provided by ELEXON) and all assumptions must be clearly stated. Output data should be in a readily usable format. Finally, the model should be flexible and capable of quick turn around.

Specifically, PTI has been tasked to:

- perform calculations of TLFs for a specified number of Sample Settlement Periods (SSPs) for Modification Proposal P198;
- present the results in a form suitable for the assessment procedure; and
- draw attention to potential issues with the fundamentals of the marginal approach proposed (MP198) arising from the exercise.

A large number of load flow calculations, marginal TLF calculations and post processing calculations were performed. All results from these calculations as well as the input data received from ELEXON and used in the calculations were delivered to ELEXON in electronic format on a CD.

TLMs presented in this report were provided by ELEXON on the basis of the MP198 Load Flow Modelling results Siemens PTI submitted to ELEXON.

Additional Task. During the project work a methodological issue was raised and the MP198 Modification Group asked additional results to be produced using an alternative method for calculating Zonal TLFs for each Sample Settlement Period.

This report presents a suitable selection of the project results. Section 3 presents input data received from ELEXON for the modelling exercise in this project. Section 4 presents the assumptions made and methodological approach used in the modelling exercise in this project. Section 5 presents the results from the modelling calculations for the Modification Proposal P198. Section 6 describes a methodological issue, noted during the project work, with intention to draw P198 Modification Group 's attention to this issue raised; it also presents additional results obtained by using an alternative method to calculate Zonal TLFs for each SSP. The report does not have conclusions as they will arise from the P198 Modification Group assessment procedure.

3 INPUT DATA FOR THE MODELLING EXERCISE

3.1 Settlement Period data

Table 1: List of Settlement Periods for which delivery and offtake metered volumes data were provided by ELEXON

Tasks for which these SSPs were used	Sample Settlement Periods (SSPs) used
There were 623 Sample Settlement Periods (SSPs) as for the baseline input data set (Data Set 1), of which the Metered Volumes were used in different arrangements (annual, seasonal and monthly) and in association with different networks or algorithms for different tasks. These tasks were Task 1, Task 2, Task 3, Task 4, Task 5, and Task 12. Particular SSPs were extracted from this set and Task 1 for purpose of Task 7.	623 SSP (Apr. 05 to Jan. 06) ➔ Winter 143 SSPs Spring 165 SSPs Summer 157 SSPs Autumn 158 SSPs ➔ April 05 113 SSPs May 05 52 SSPs June 05 53 SSPs July 05 54 SSPs Aug. 05 50 SSPs Sept. 05 52 SSPs Oct. 05 55 SSPs Nov. 05 51 SSPs Dec. 05 53 SSPs Jan. 06 90 SSPs
These SSPs formed 16 sets to represent typical days for Task 2	Spring Peak (W*) 13042005 48 SSPs Spring Peak (NW**) 09042005 48 SSPs Spring Off Peak (W) 30052005 48 SSPs Spring Off Peak (NW) 29052005 48 SSPs Summer Peak (W) 22062005 48 SSPs Summer Peak (NW) 18062005 48 SSPs Summer Off Peak (W) 29082005 48 SSPs Summer Off Peak (NW) 06082005 48 SSPs Autumn Peak (W) 23112005 48 SSPs Autumn Peak (NW) 19112005 48 SSPs Autumn Off Peak (W) 01092005 48 SSPs Autumn Off Peak (NW) 03092005 48 SSPs Winter Peak (W) 23012006 48 SSPs Winter Peak (NW) 07012006 48 SSPs Winter Off Peak (W) 27122005 48 SSPs Winter Off Peak (NW) 24122005 48 SSPs
This one was used for Task 6	A particularly selected SSP
These sets were used for Task 8 and Task 9	4 different and specially prepared sets of 623 SSPs
These 8 single SSP Metered Volumes data sets were used in Task 10	Spring South 20050413-29 1 SSP Spring North 20050413-29 1 SSP Autumn South 20051123-33 1 SSP Autumn North 20051123-33 1 SSP Summer South 20050622-26 1 SSP Summer North 20050622-26 1 SSP Winter South 20060123-38 1 SSP Winter North 20060123-38 1 SSP
These sets were used for Task 11	6 different and specially prepared sets of 623 SSPs

* – Working Day
** – Non-Working Day

Delivery and off-take metered volumes data for a considerable number of Settlement Periods from the recent past were provided by ELEXON for the calculation of TLFs for the 12 specified Tasks (see **Table 1**).

These Tasks, specified by the Terms of Reference, were designed with the aim to demonstrate the key representative features of Modification Proposal P198, required by the P198 Modification Group for the assessment procedure. For this purpose each of the Tasks combines selected Settlement Periods data with particular network data.

Past delivery and off-take metered volumes data for the representative SPs were used in calculating characteristic TLFs.

3.2 Network data

In order to enable load flow calculations and calculations of marginal TLFs, the delivery and off-take metered volumes data for specific Settlement Periods (**Table 1**) were accompanied with appropriate detailed network data. The list of networks for which data were provided is given in **Table 2** together with the indication in which tasks these networks were used.

Table 2: List of network data provided by ELEXON

Network Data	
Network	**Tasks the network data were used for**
Intact (winter) network	Task 1, Task 2, Task 3, Task 4, Task 5 (winter), Task 7, Task 8, Task 9, Task 10, Task 11
A modified Intact (winter) network (so that Scottish 132 kV network does not contribute to the variable heating losses)	Task 12
Representative spring network	Task 5 (spring)
Representative summer network	Task 5 (summer)
Representative autumn network	Task 5 (autumn)
An indicative network reflecting a situation with constraints affecting the flows	Task 6

The network data were originally prepared by National Grid and delivered to Siemens PTI by ELEXON. The network data contained lists of network elements in operation and their electric parameters required for the calculations. Network elements included are chosen and represented in such a way to serve the purpose of this modelling project. In that respect the networks used in this project:

i) included all network elements that belong to the GB transmission system,

ii) excluded the generators' transformers, due to the existing metering arrangements,

iii) included a few network elements not belonging to the GB transmission system, but significantly influencing its power flows (they were represented with reactive electric parameter only and with resistance set to zero – an approach suitable when DC load flow model is used as in this project).

Note: During the modelling calculations it was noted that a relatively small number of elements in Scotland not belonging to the GB transmission system were included with their resistance not set to zero. An analysis was made for 09/04/2005 29 SP. Since the heating losses in these elements accounted for less than 0.17% of the total GB heating losses and for estimated less than 0.7% of total Scottish heating losses the conclusion was that influence of these elements on the modelling results is negligible. Thus Siemens PTI was instructed to complete the modelling calculations with such network data.

The intact network was assumed to be most complete (i.e. to have the largest and most complete set of network elements in operation). The representative/indicative networks were prepared/chosen to reflect typical availability of network elements and their typical operational arrangements. The network for Task 12 was produced from the intact network where resistance of Scottish 132 network elements was set to zero.

Actual network data from the past were used to produce the intact and representative/indicative networks for the modelling calculations.

4 MODELLING APPROACH

4.1 Method

Modification Proposal P198 proposes calculation of zonal ½ h TLMs based on zonal ½ h TLFs, which are based on annual averages of nodal scaled marginal TLFs. The proposed zones are GSPG zones, unique for both demand and generation (see Section 5.1).

The adopted method for calculation of Transmission Loss Factors (TLFs) is that of DC calculations as described in ELEXON's document "Load Flow Model Specification for the Calculation of Nodal Transmission Loss Factors" (June 2003, version 1.0, Author CVA Programme). While this is related to calculation of Nodal TLFs, Zonal TLFs, and (Adjusted) Annual Average Zonal TLFs were calculated by the methodology described in ELEXON's document "Transmission Loss Factor Agent Service Description", Version 2.0, September 2003. Therefore, zonal ½ h TLFs were calculated as average of nodal scaled marginal ½ h TLFs weighted by the sum of absolute values of demand and generation at each node in a zone, for each Settlement Period (½ h) considered. Annual average zonal TLFs were calculated using a time weighted averaging of zonal ½ h TLFs. The alternative method to calculate ½ h Zonal TLFs (for the additional Task 1b), where net Nodal Power Flows are used in weighted averaging and that separately for net delivering and net off-taking nodes, is described in Section 6

For the calculations the standard National Grid's slack at Cowley was used.

4.2 Software tools

Siemens PTI utilised LFM System Software, which originates from our engagement as TLF Agent in period 2003-04.

LFM System Software consists of two components:

- LFM Core Software, and
- LFM Operational Software.

LFM Core Software is Siemens PTI's proprietary software tool called PSS/E. LFM Operational Software is a software component that Siemens PTI developed for BSCCo and that works on the basis of the LFM Core Software. LFM Operational Software is BSCCo's property. LFM System Software was thoroughly tested in 2003. During the MP198 Modelling Project some variants of the LFM Operational Software were produced in order to obtain some additionally required results, while the core of the code remained intact.

Input data (see Section 3) and most of output data were in the format described in ELEXON's document "TLFA User Requirements Specification" (17th October 2003, Issue 3.0, Version 1.0; section 5 "Interface Requirements and Definitions").

The intention was to employ well defined methodology and maximally utilise the existing, well tested software tools.

5 PROJECT RESULTS

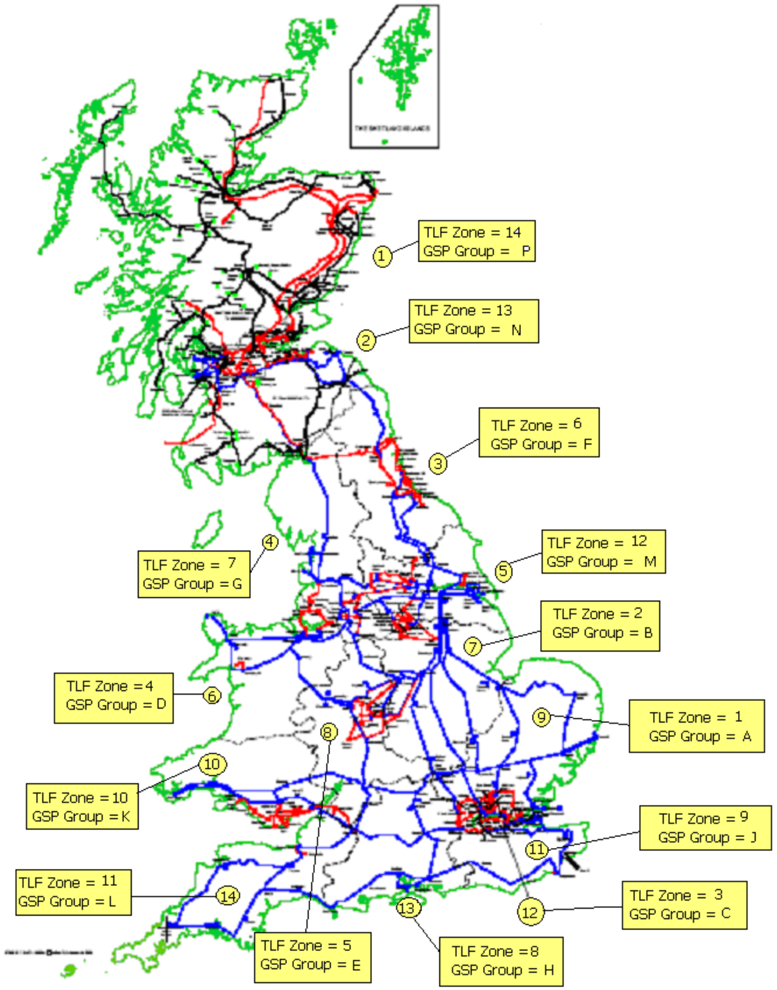


Figure 1: Guidance for the Zones as applied in the Project

This section presents the MP198 Modelling Project results. The project work was divided into 12 Tasks and results for each Task are given in separate section. The first section describes the Zones as implemented in this project.

5.1 Zones as applied in the MP198 Modelling Project

MP198 suggests that "the applicable zones would be the geographical area in which a GSP Group lies, determined by the Panel (applying such criteria as it shall decide in its discretion)." This indicated unique zones for both generation and demand.

The Network Mapping Statement, input data provided by ELEXON, maps the network nodes of relevance to the zones. **Figure 1** can be used as for an approximate guidance for the zones as applied in the Project. Zone area numbers (1 to 14) in **Figure 1** served a convenient sorting of the results in geographical perspective. TLF Zone numbers in **Figure 1** correspond to GSP Group ordered letters (i.e. 1 corresponds to A, 2 to B, etc). The Key to zones is presented in **Table 3**

Table 3: Key to Zone numbers and codes

No. on picture	GSP Group's area name	GSP Group code	TLF Zone Number
1	NORTH of SCOTLAND GSP	GSPG-P	14
2	SOUTH of SCOTLAND GSP	GSPG-N	13
3	NORTHERN	GSPG-F	6
4	North Western	GSPG-G	7
5	Yorkshire Electricity	GSPG-M	12
6	Merseyside and North Wales	GSPG-D	4
7	East Midlands	GSPG-B	2
8	Midlands	GSPG-E	5
9	Eastern GSP Group	GSPG-A	1
10	South Wales	GSPG-K	10
11	South Eastern	GSPG-J	9
12	LE Distribution	GSPG-C	3
13	Southern	GSPG-H	8
14	South Western	GSPG-L	11

5.2 Task 1: Establish baseline TLFs

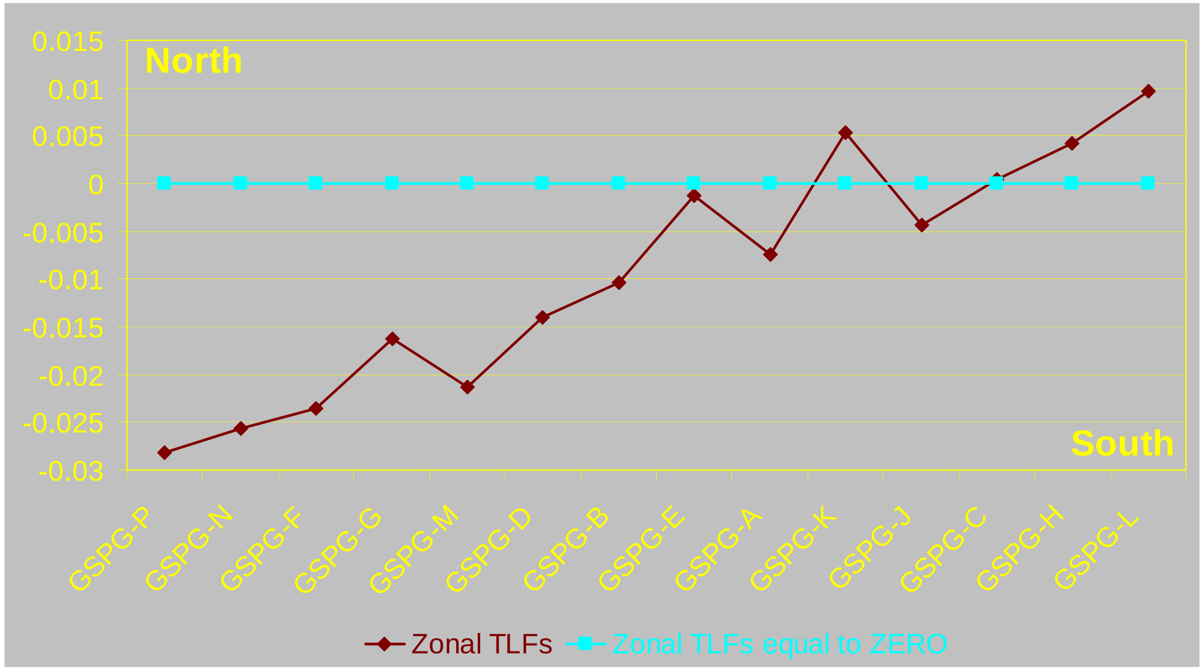


Figure 2: Baseline Adjusted Annual Average Zonal TLFs

Table 4: Baseline Adjusted Annual Average Zonal TLFs

Zone	AAA Zonal TLFs	Zone	AAA Zonal TLFs
GSPG-P	-0.02818	GSPG-E	-0.00133
GSPG-N	-0.02561	GSPG-A	-0.00742
GSPG-F	-0.02355	GSPG-K	0.0053
GSPG-G	-0.01625	GSPG-J	-0.0043
GSPG-M	-0.02127	GSPG-C	0.00039
GSPG-D	-0.01399	GSPG-H	0.00414
GSPG-B	-0.01038	GSPG-L	0.00963

Currently BSC calculates TLMs with TLFs set to zero. MP 198 proposes Adjusted Annual Average Zonal TLFs that will vary geographically, reflecting the contribution to variable heating system losses by the generation and demand.

As for calculation of the baseline Adjusted Annual Average Zonal TLFs ELEXON selected 623 Sample Settlement Period (SSPs) from the period April 2005 to January 2006 inclusively. The selection of these 623 SSPs reflected the assumption that, for the purpose of this modelling project, February 2006 can be sufficiently well represented by January 2006 and that March 2006 can be sufficiently well represented by April 2005. The use of 623 SSPs is similar in size to what could be the sample for live calculations of the Adjusted Annual Average Zonal TLFs for use in the settlement procedure.

Therefore, the Metered Volumes used in calculation were selected from ELEXON's past records and coupled with the intact transmission systems network, provided by National Grid from their practice.

Figure 2 presents the calculated baseline Adjusted Annual Average Zonal TLFs as put against TLFs currently used in the settlement procedure.

The meaning of specially arranged signs of the Adjusted Annual Average Zonal TLFs in **Figure 2** should be noted: a negative Adjusted Annual Average Zonal TLFs indicates that generation in that zone contributes to increasing variable heating system losses and should be charged accordingly. Demand in that same zone contributes to decreasing and should be credited accordingly.

Introduction of P198 would result in geographically variable Zonal TLFs and thus in geographically variable TLMs.

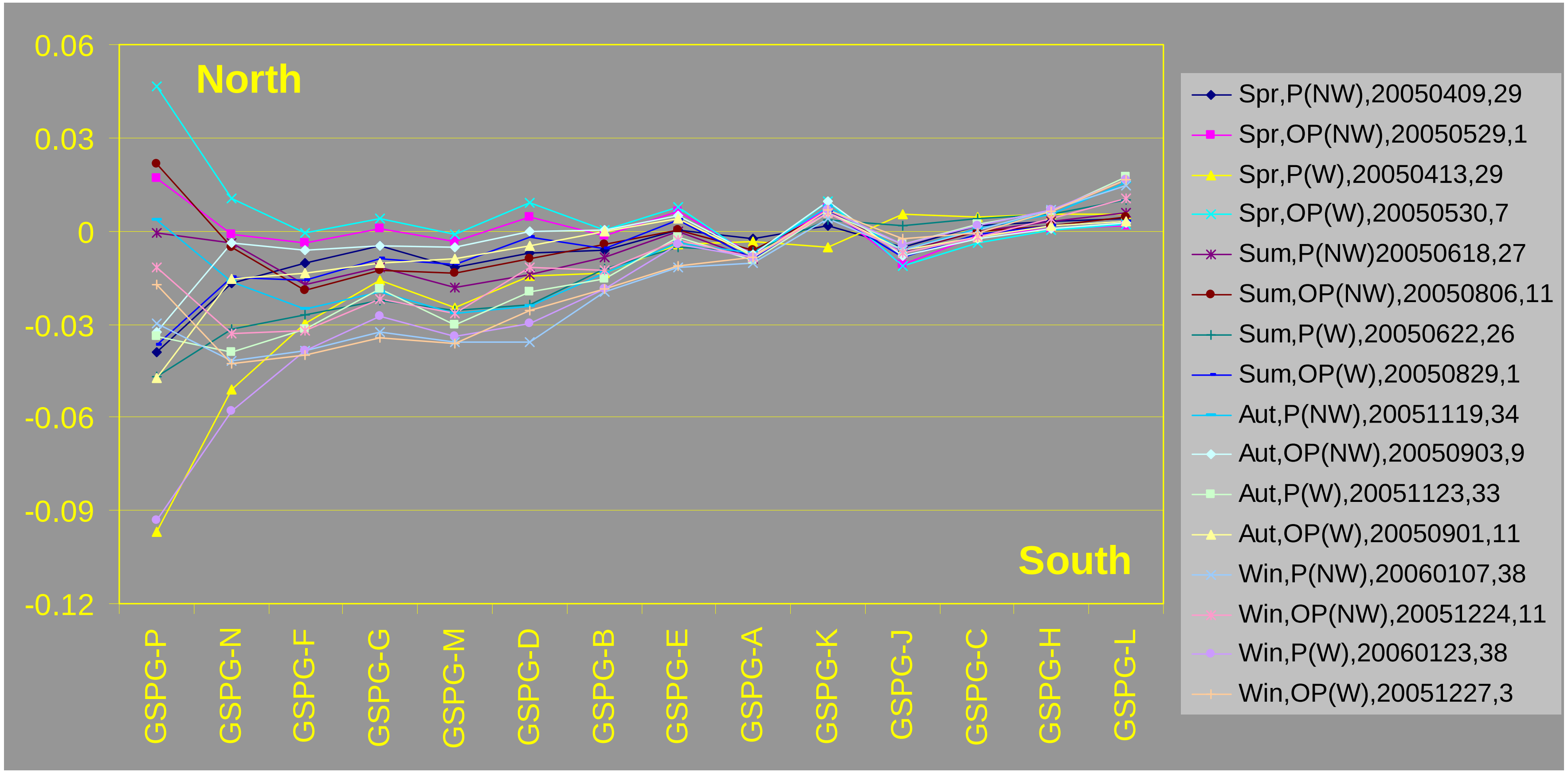


Figure 3: Illustrative variability of Adjusted SSP Zonal TLFs on the basis of which the baseline Adjusted Annual Average Zonal TLFs were produced (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working); the 16 SSPs were selected to be representative.

The baseline Adjusted Annual Average Zonal TLFs in **Figure 2** are obtained by two tier averaging process. In the first step, for a particular SSP and particular Zone, Zonal TLF was produced by weighted averaging Nodal TLFs in that Zone and for that SSP, weighted by nodal power flows (that reflect the Metered Volumes). Then SSP Zonal TLFs were averaged across 623 SSPs using a time weighted averaging. **Figure 3** indicates variability of SSP Zonal TLFs that make the baseline Adjusted Annual Average Zonal TLFs. This illustration is based on a 16 SSPs selected by ELEXON.

For some Zones there is a greater time variability in SSP Zonal TLFs behind Annual Average Zonal TLFs than for others

For illustration, Transmission Loss Multipliers (TLMs) for Delivery and for Off-taking are given for peak SSP and for trough SSP – **Figure 4** and **Figure 5** respectively. These illustrative baseline TLMs are presented in comparison with Delivery and for Off-taking TLMs that were calculated using the currently applied approach (i.e. that of using TLFs = 0).

All TLMs in this report were calculated by ELEXON from TLFs submitted by Siemens PTI.

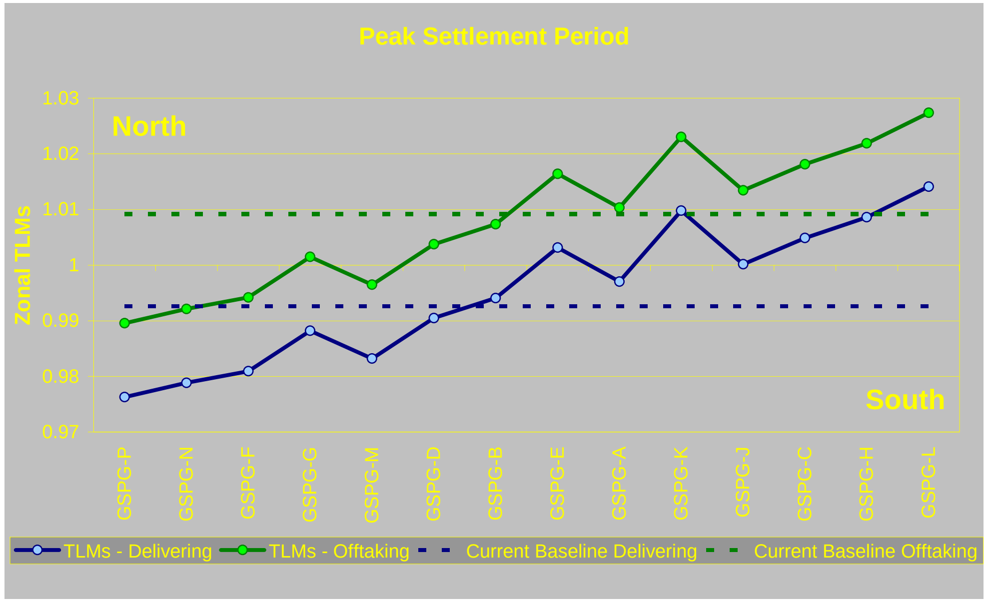


Figure 4: Illustrative Delivery and Off-take TLMs for Peak SSP as compared to current Delivery and Off-take TLMs for the same SSP

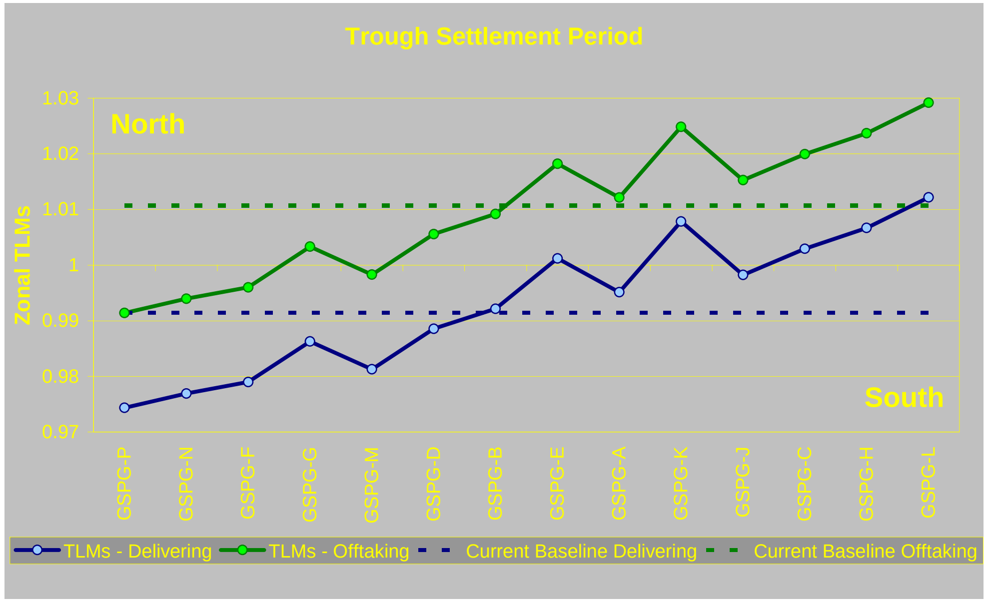


Figure 5: Illustrative Delivery and Off-take TLMs for Trough SSP as compared to current Delivery and Off-take TLMs for the same SSP

Under MP198 TLMs would change and that change would be different in different geographical areas.

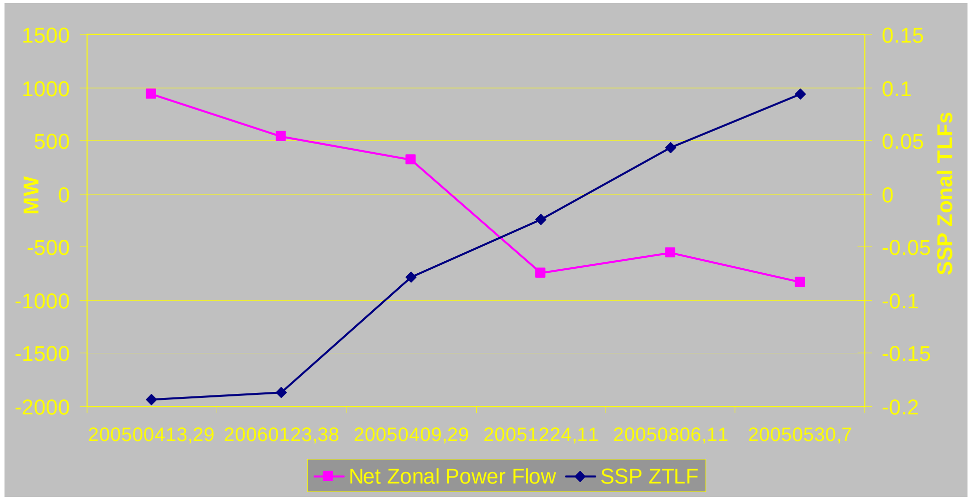


Figure 6: Total of Net Nodal Power Flows in GSPG-P zone (Net Zonal Power Flow) against the SSP Zonal TLFs

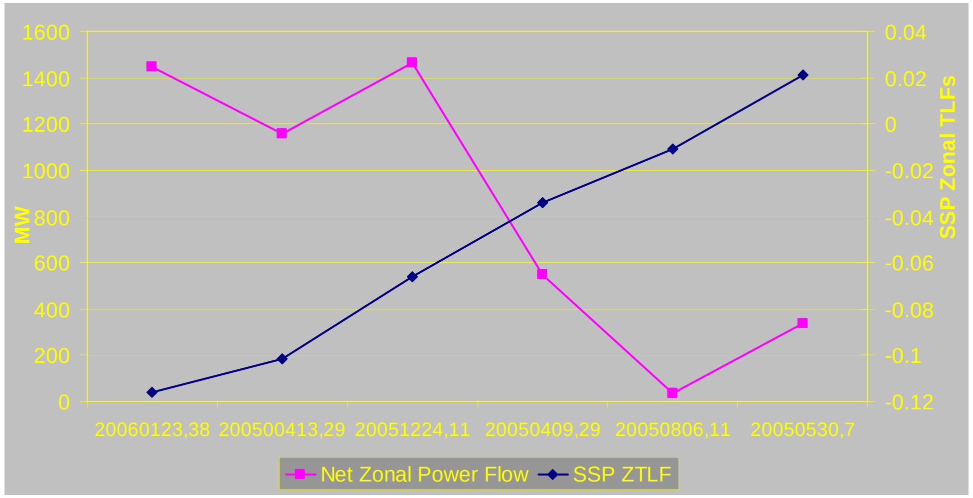


Figure 7: Total of Net Nodal Power Flows in GSPG-N zone (Net Zonal Power Flow) against the SSP Zonal TLFs

Notably greater variability of representative Adjusted SSP Zonal TLFs in the north than in the south (**Figure 3**) prompted an analysis with the aim to offer an explanation.

The analysis focused on GSPG-P and GSPG –N zones as showing most variability in the Adjusted SSP Zonal TLFs.

Figure 6 and **Figure 7** present relation between total zonal net power flows and the Adjusted SSP Zonal TLFs for GSPG-P and GSPG –N zones respectively, for a selection of representative SSPs. These figures demonstrate a strong relation between total zonal net power flows and the Adjusted SSP Zonal TLFs. **Figure 8** (prepared by ELEXON) further demonstrate for GSPG-P zone the variability of total zonal Delivering/Offtaking (which is directly related to total zonal net power flows).

Therefore, the observed variability in the Adjusted SSP Zonal TLFs for GSPG-P and GSPG –N zones is consistent with Delivering/Offtaking activities in these zones.

It should be noted that both zones, and particularly SGPG-P zone, are at the edge of the transmission system, which, to an extent, has a potential to reduce the influence of other zones on TLFs in these two zones. Nevertheless, it is always the combination of the factors that make particular TLFs, most notably (i) Delivering/Offtaking of the considered element, (ii) Delivering/Offtaking of the other elements in the system, and (iii) the network characteristics.

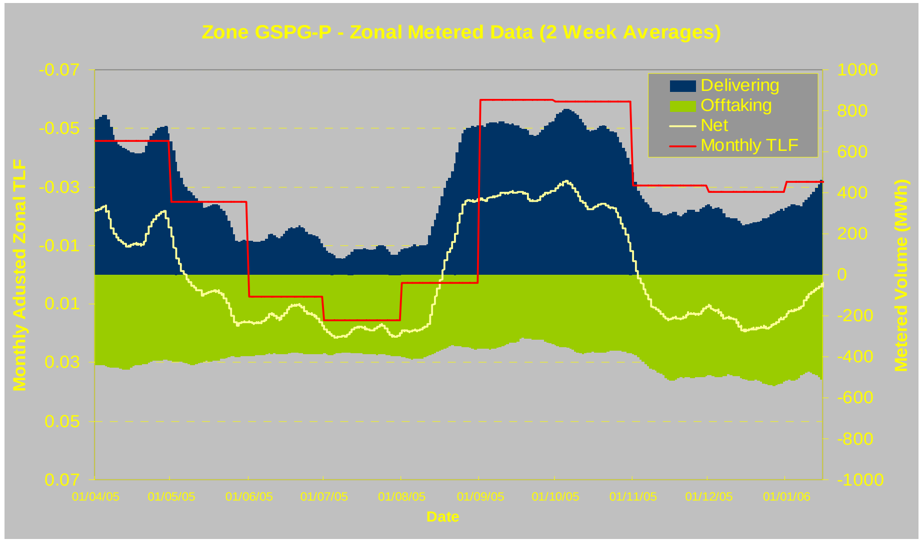


Figure 8: Variability of Monthly TLFs and variability of Total Zonal Delivering/Offtaking for GSPG-P zone (from ELEXON)

5.3 Task 2: Considering temporal variability of TLFs

The outputs from this Task are:

- 4 sets of Seasonal Average Zonal TLFs;
- 10 sets of Monthly Average Zonal TLFs; and
- 16 sets of Daily Average Zonal TLFs.

This task was set with the following objectives:

- To compare the Task outputs to Annual Average Zonal TLFs;
- To consider the extent to which Seasonal, Monthly or Daily Average Zonal TLFs deviate from corresponding Annual Average Zonal TLFs
- To support consideration of potential alternatives

5.3.1 Task 2: Seasonal Average Zonal TLFs

Figure 9 presents the Adjusted Seasonal Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs. **Figure 10** presents the envelope of variations of Adjusted Seasonal Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs (envelope lines are not coincident with any seasonal line).

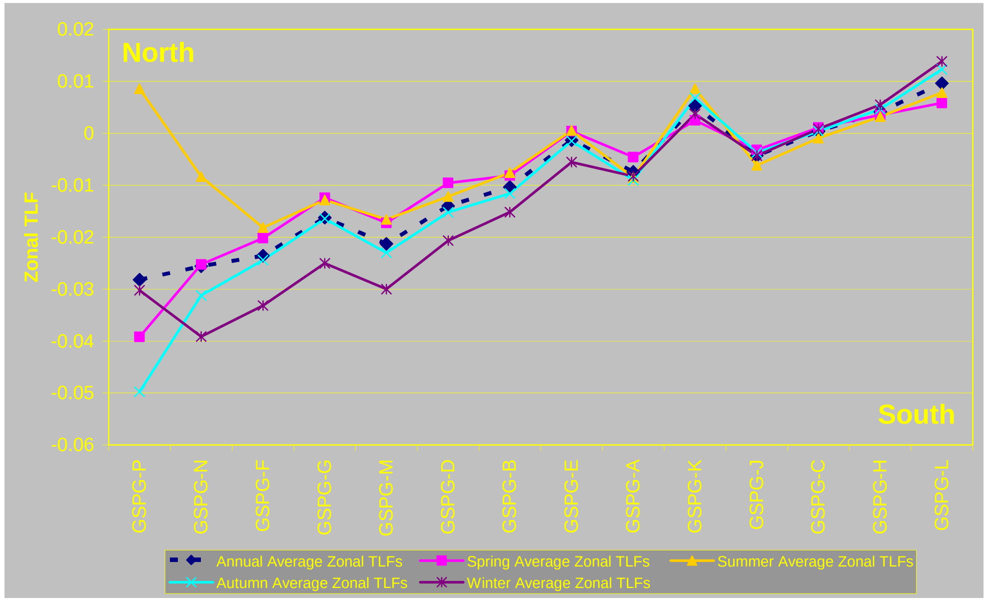


Figure 9: Adjusted Seasonal Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs

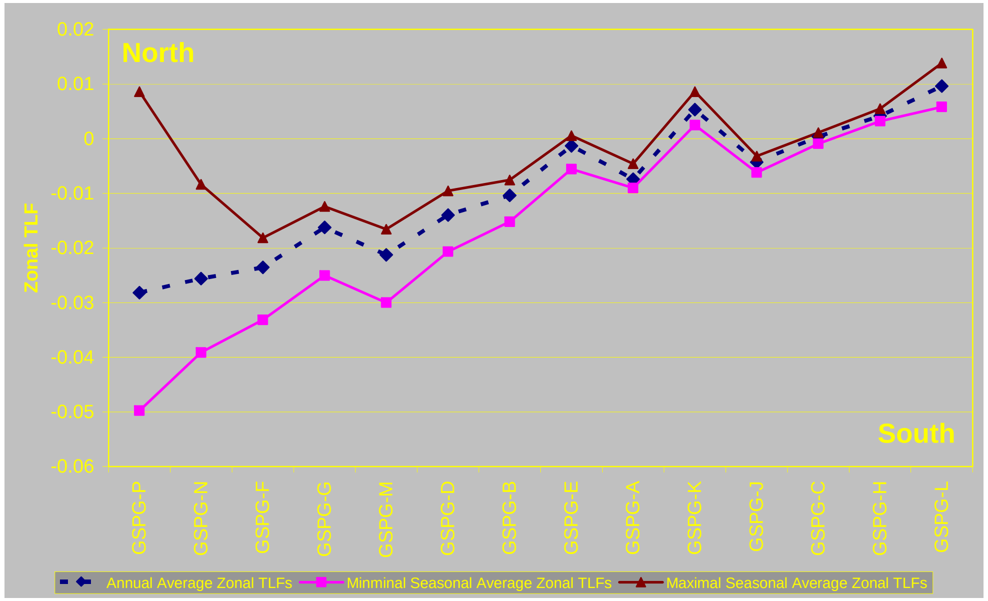


Figure 10: Envelope of variations of Adjusted Seasonal Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs

There is a greater variability of Adjusted Seasonal Average Zonal TLFs in the north than in the south.

For illustration, Delivery and Off-taking Zonal TLMs were calculated for seasonal peak SPs using appropriate Adjusted Seasonal Average Zonal TLFs. These Zonal TLMs are presented in **Figure 11**, **Figure 12**, **Figure 13**, and **Figure 14** for spring peak SP, summer peak SP, autumn peak SP, and winter SP respectively. For better understanding of how the use of Adjusted Seasonal Average Zonal TLFs could work, also presented in these figures are Delivery and Off-taking Zonal TLMs (for these seasonal peak SPs) calculated on the basis of Adjusted Annual Average Zonal TLFs. The figures also contain reference to currently used TLMs (calculated for the same SPs).

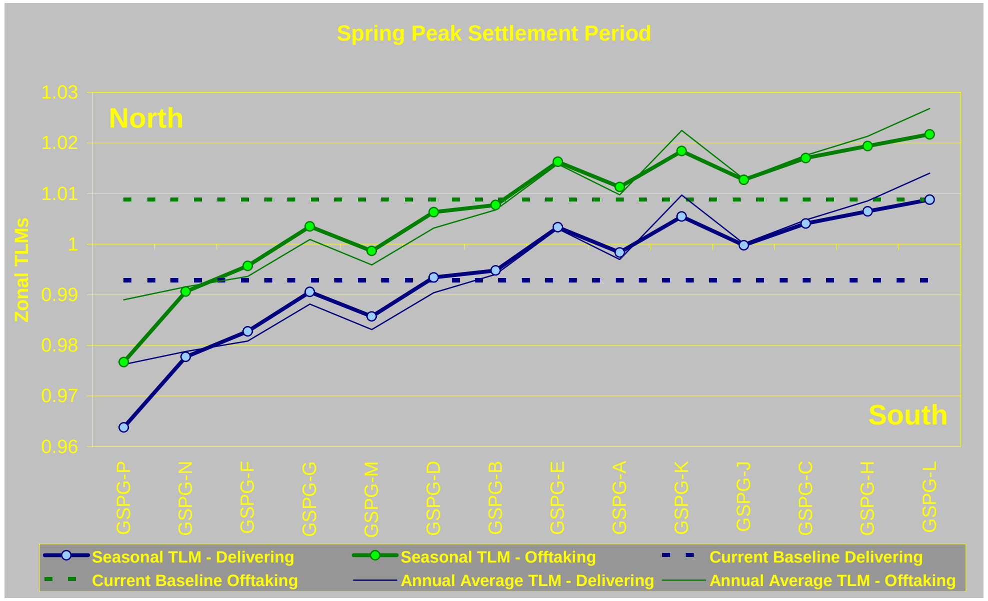


Figure 11: Delivery and Off-taking Zonal TLMs for the <u>spring</u> peak SP, calculated on the basis of <u>spring</u> Adjusted Seasonal Average Zonal TLFs, and on the basis of Adjusted Annual Average Zonal TLFs put against current TLMs (based on TLF=0)

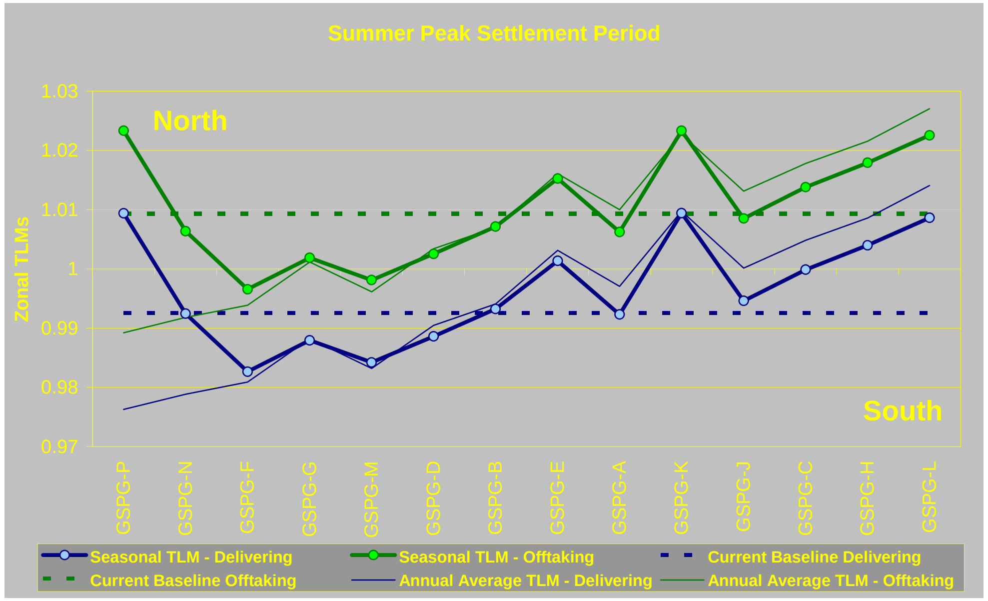


Figure 12: Delivery and Off-taking Zonal TLMs for the <u>summer</u> peak SP, calculated on the basis of <u>summer</u> Adjusted Seasonal Average Zonal TLFs, and on the basis of Adjusted Annual Average Zonal TLFs put against current TLMs (based on TLF=0)

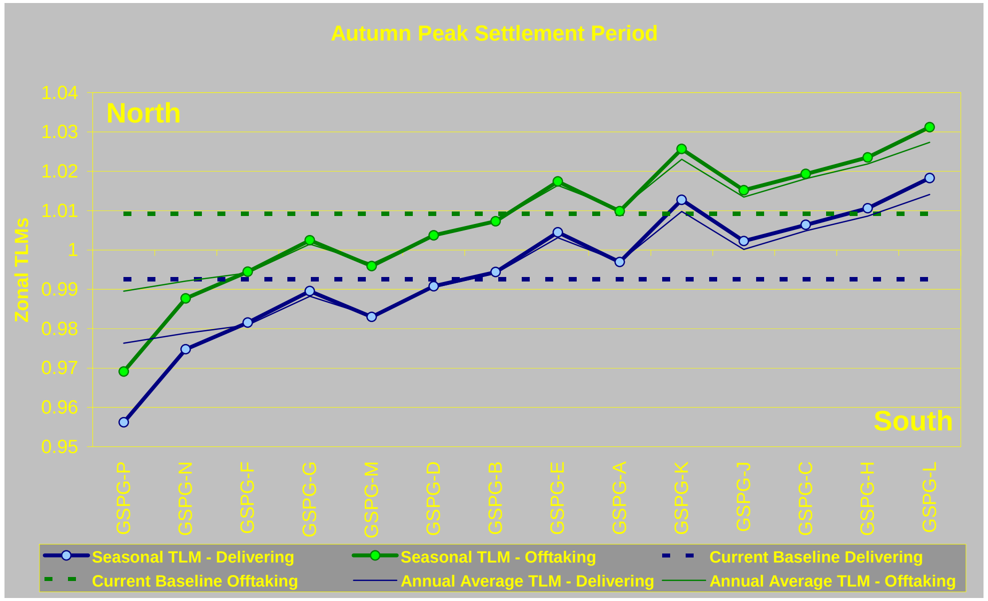


Figure 13: Delivery and Off-taking Zonal TLMs for the autumn peak SP, calculated on the basis of autumn Adjusted Seasonal Average Zonal TLFs, and on the basis of Adjusted Annual Average Zonal TLFs put against current TLMs (based on TLF=0)

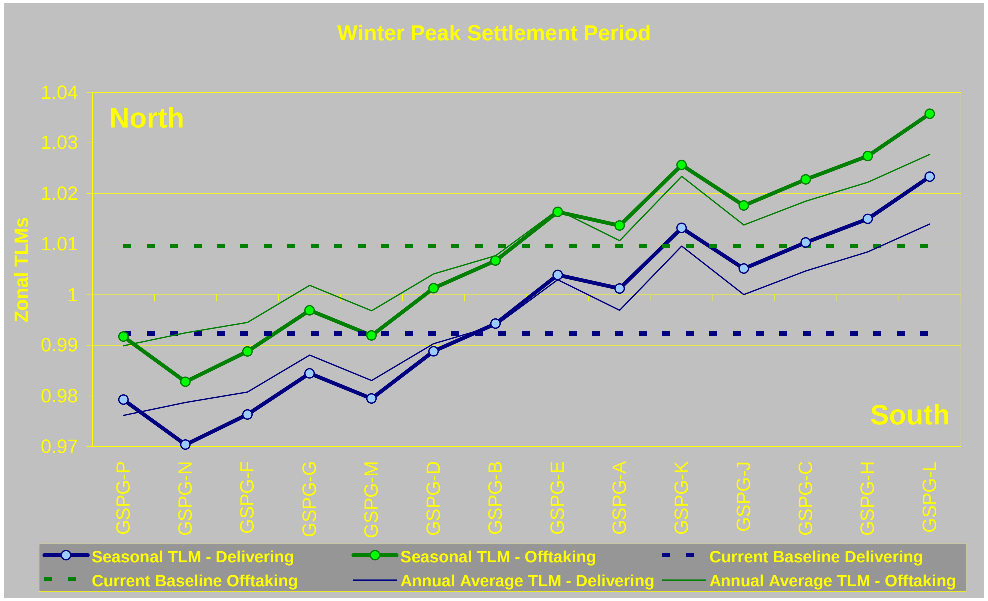


Figure 14: Delivery and Off-taking Zonal TLMs for the winter peak SP, calculated on the basis of winter Adjusted Seasonal Average Zonal TLFs, and on the basis of Adjusted Annual Average Zonal TLFs put against current TLMs (based on TLF=0)

5.3.2 Task 2: Monthly Average Zonal TLFs

Figure 15 presents the Adjusted Monthly Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs. **Figure 16** presents the envelope of variations of Adjusted Monthly Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs (envelope lines are not coincident with any monthly line).

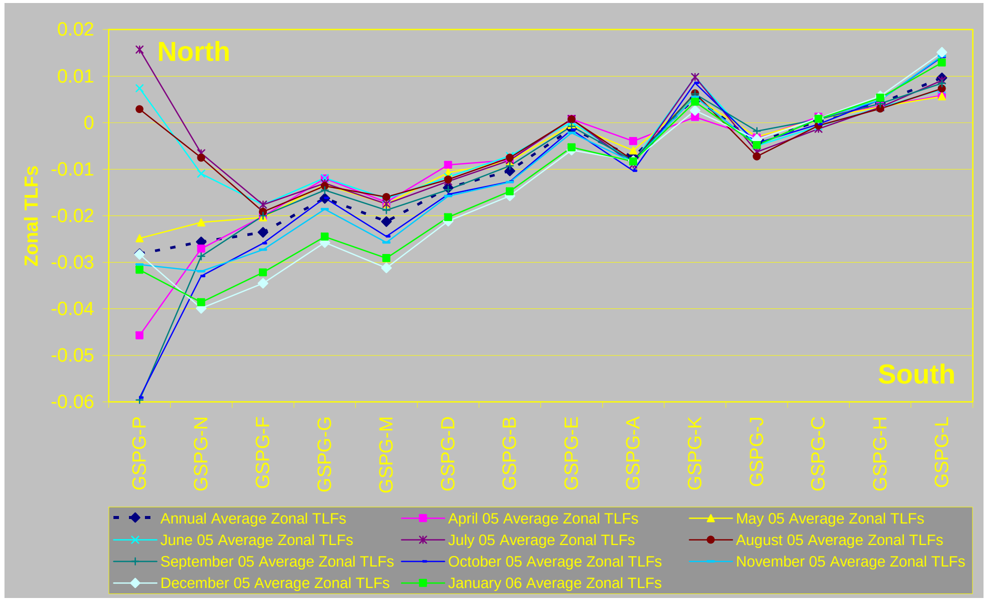


Figure 15: Adjusted Monthly Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs

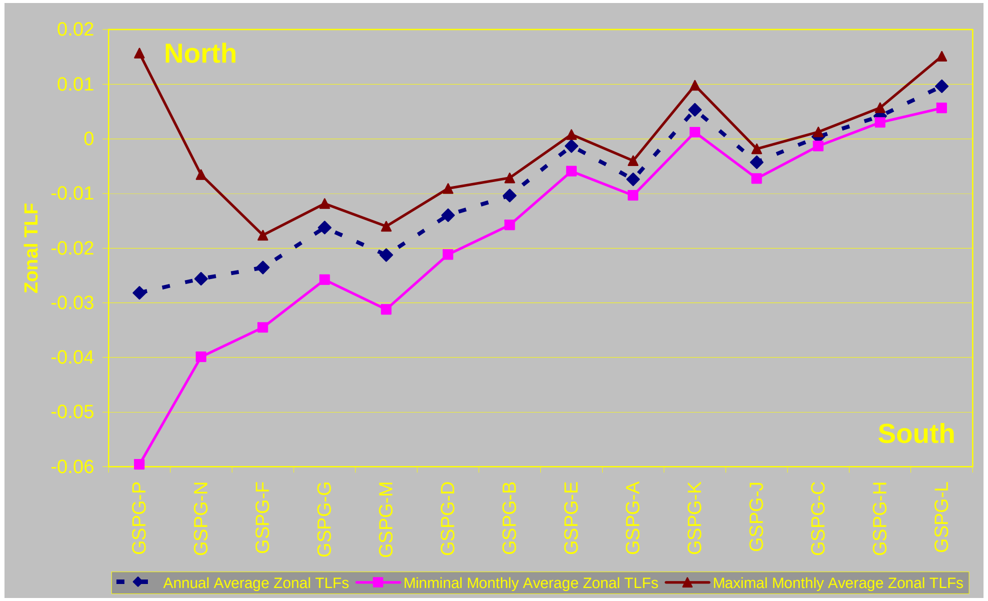


Figure 16: Envelope of variations of Adjusted Monthly Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs

There is a greater variability of Adjusted Monthly Average Zonal TLFs in the north than in the south.

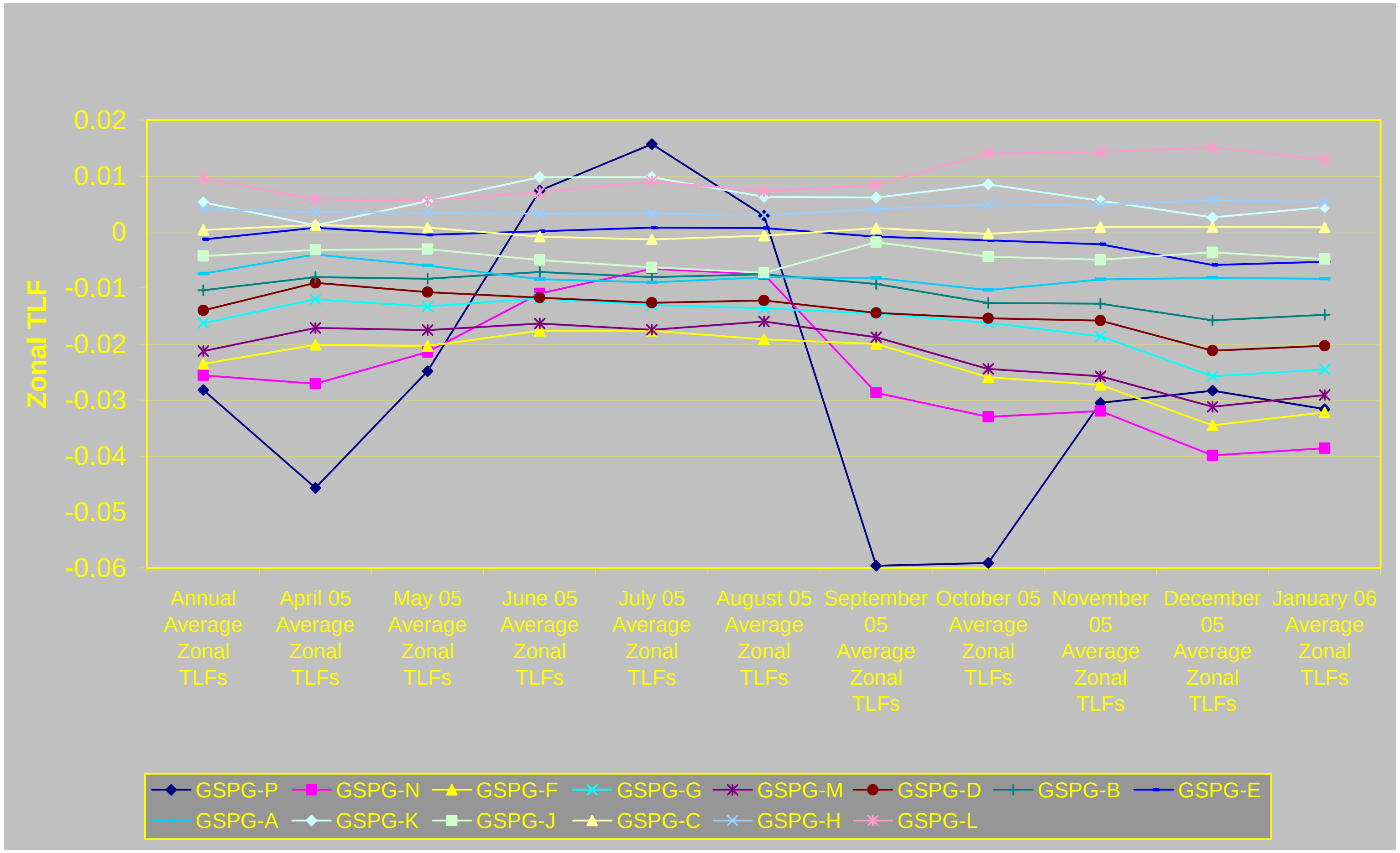


Figure 17: Fluctuation of Adjusted Monthly Average Zonal TLFs for each zone, over the considered months, starting with the Adjusted Annual Average Zonal TLF for each particular zone

Figure 17 presents for each zone the fluctuation of the Adjusted Monthly Average Zonal TLFs over the considered months, while starting with the Adjusted Annual Average Zonal TLF for each particular zone. As **Figure 15**, **Figure 17** also demonstrates a greater variability of Adjusted Monthly Average Zonal TLFs in the north than in the south.

Figure 18, **Figure 20**, **Figure 22**, and **Figure 24** present the relevant Adjusted Monthly Average Zonal TLFs for spring, summer, autumn and winter respectively and compared to the corresponding Adjusted Seasonal Average Zonal TLFs. **Figure 19**, **Figure 21**, **Figure 23**, and **Figure 25** present the envelope of variations of Adjusted Monthly Average Zonal TLFs for spring, summer, autumn and winter respectively, around the corresponding Adjusted Seasonal Average Zonal TLFs (envelope lines are not coincident with any monthly line). The envelopes around the Adjusted Seasonal Average Zonal TLFs are much closer than the envelope around the Adjusted Annual Average Zonal TLFs (**Figure 16**).

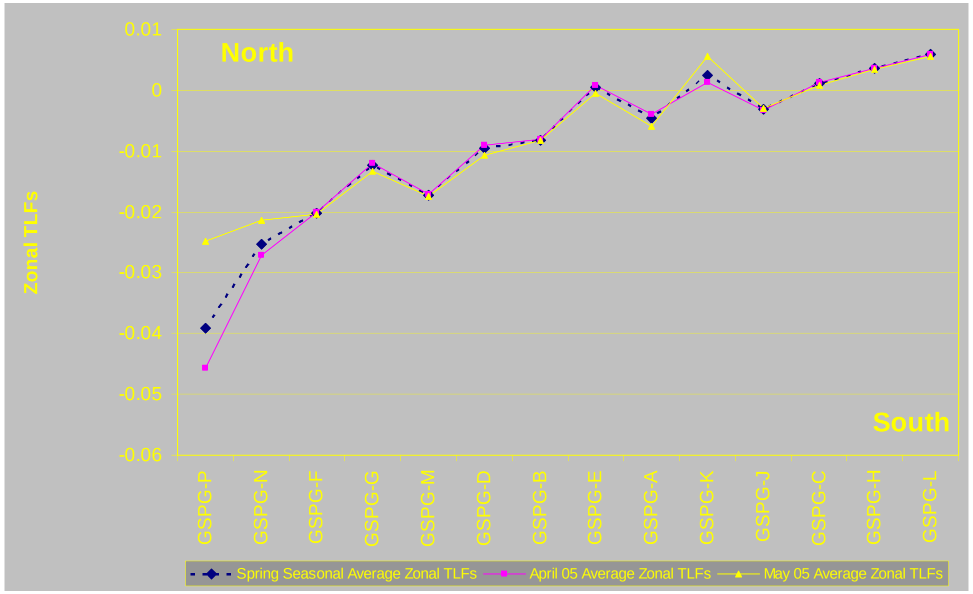


Figure 18: Adjusted Monthly Average Zonal TLFs for spring months compared to the Spring Adjusted Seasonal Average Zonal TLFs

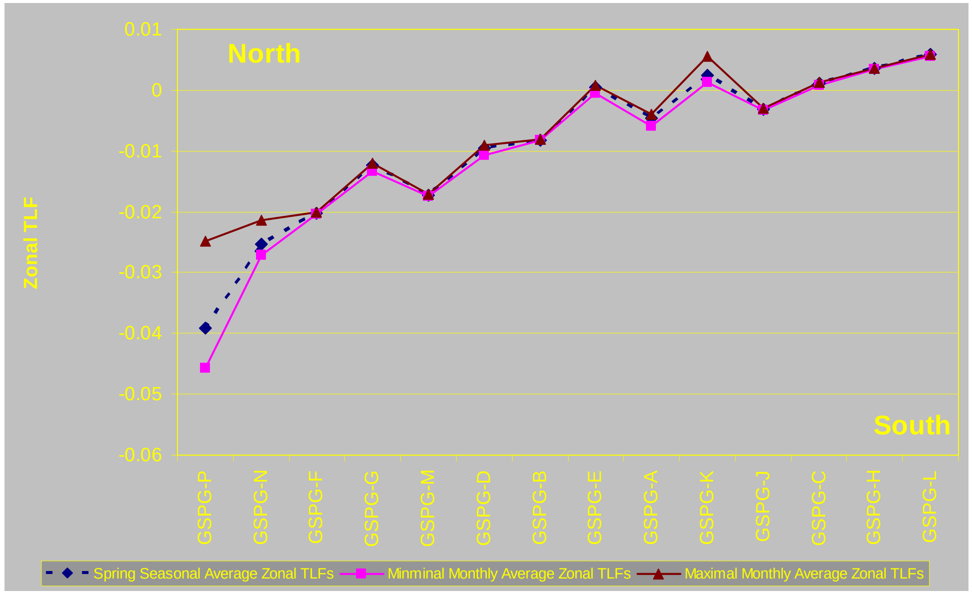


Figure 19: Envelope of variations of Adjusted Monthly Average Zonal TLFs for spring months around the Spring Adj. Seasonal Average Zonal TLFs

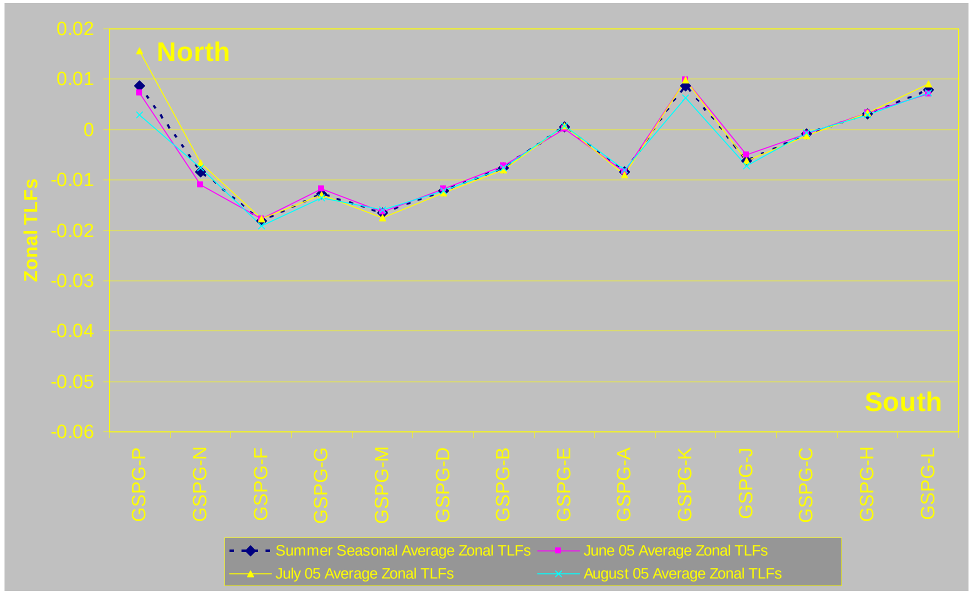


Figure 20: Adjusted Monthly Average Zonal TLFs for summer months compared to the Summer Adjusted Seasonal Average Zonal TLFs

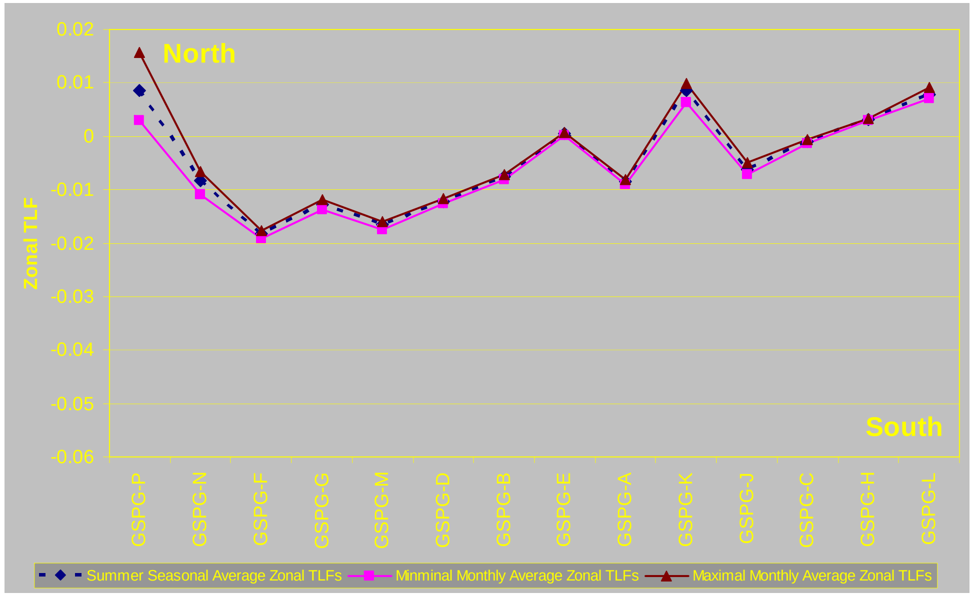


Figure 21: Envelope of variations of Adjusted Monthly Average Zonal TLFs for summer months around the Summer Adj. Seasonal Average Zonal TLFs

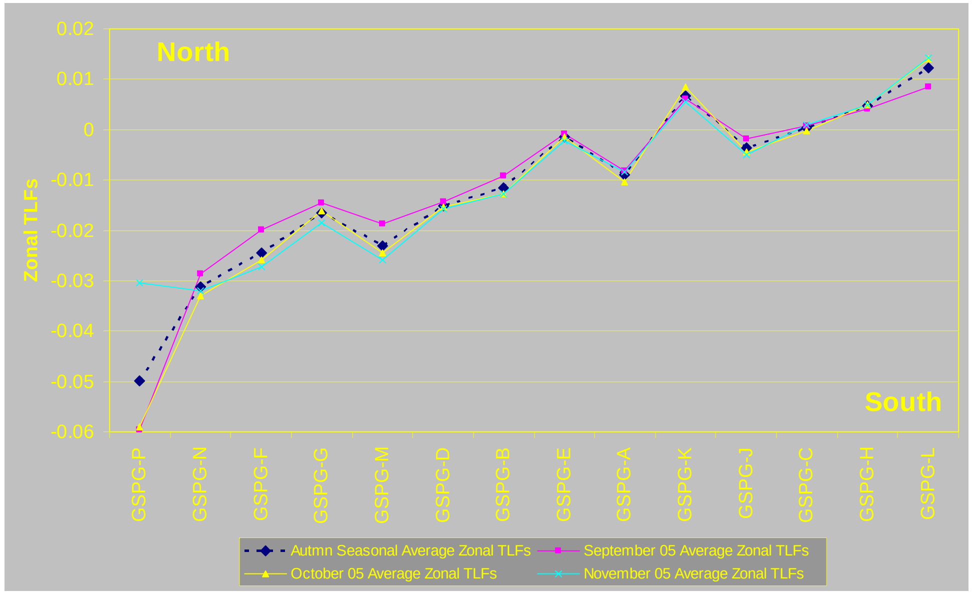


Figure 22: Adjusted Monthly Average Zonal TLFs for autumn months compared to the Autumn Adjusted Seasonal Average Zonal TLFs

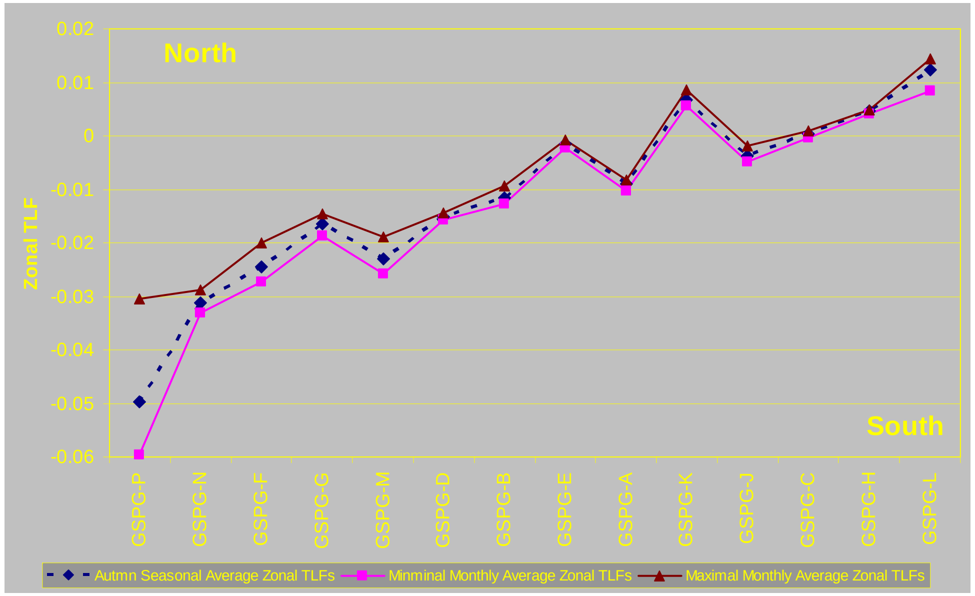


Figure 23: Envelope of variations of Adjusted Monthly Average Zonal TLFs for autumn months around the Autumn Adj. Seasonal Average Zonal TLFs

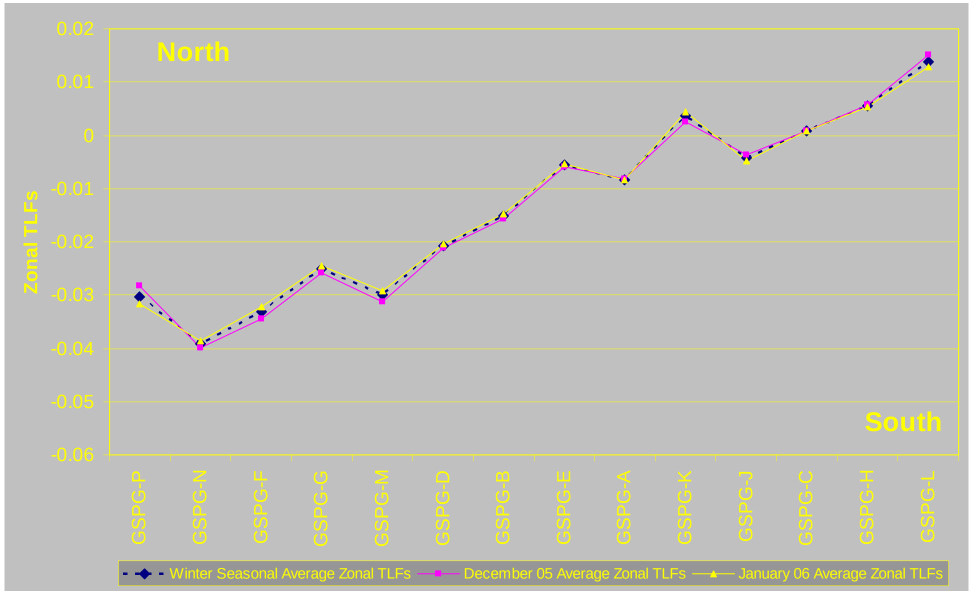


Figure 24: Adjusted Monthly Average Zonal TLFs for <u>winter</u> months compared to the <u>Winter</u> Adjusted Seasonal Average Zonal TLFs

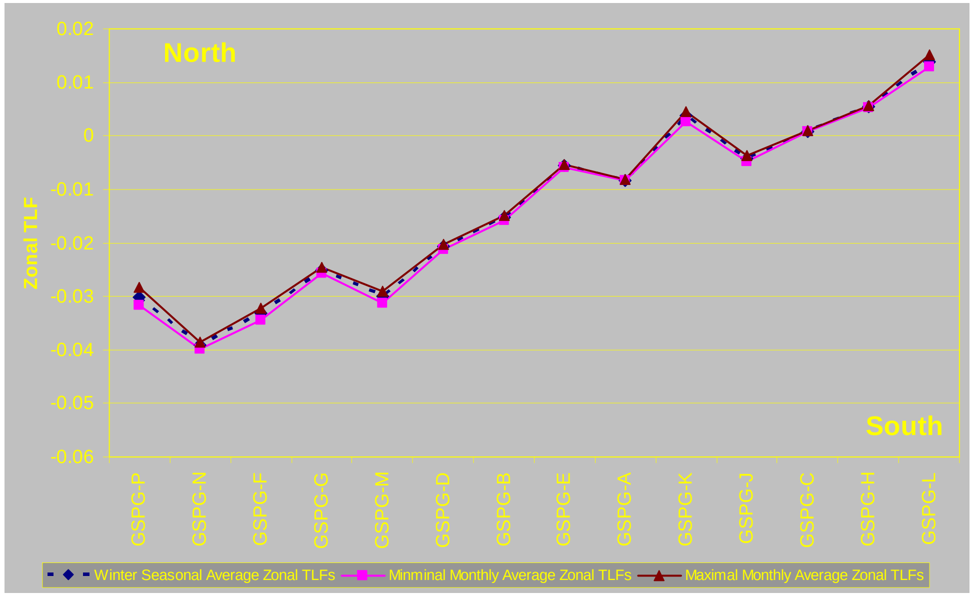


Figure 25: Envelope of variations of Adjusted Monthly Average Zonal TLFs for <u>winter</u> months around the <u>Winter</u> Adj. Seasonal Average Zonal TLFs

Monthly Average Zonal TLFs are much closer to Seasonal Average Zonal TLFs than to Annual Average Zonal TLFs.

5.3.3 Task 2: Daily Average Zonal TLFs

A selection of 16 characteristic days was made by ELEXON (see **Table 1** for the detailed list) and appropriate input data provided for this Task. Each characteristic day was represented with Metered Volume for all 48 SPs.

Figure 26 presents the Adjusted Daily Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs. **Figure 27** presents the envelope of variations of Adjusted Daily Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs (envelope lines are not coincident with any daily line).

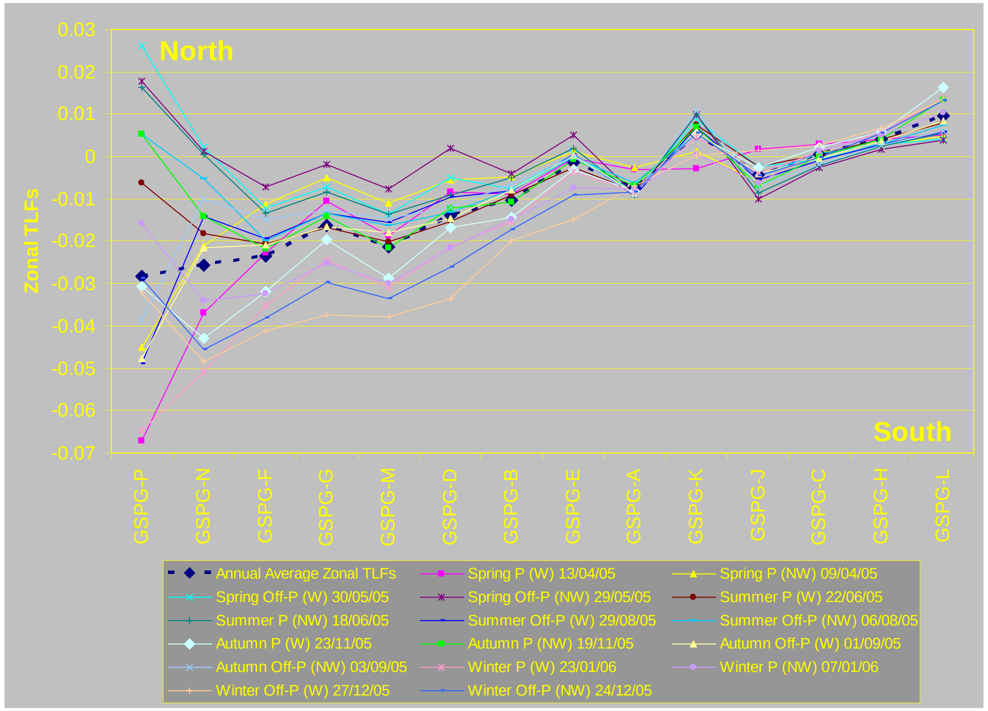


Figure 26: Adjusted Daily Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working)

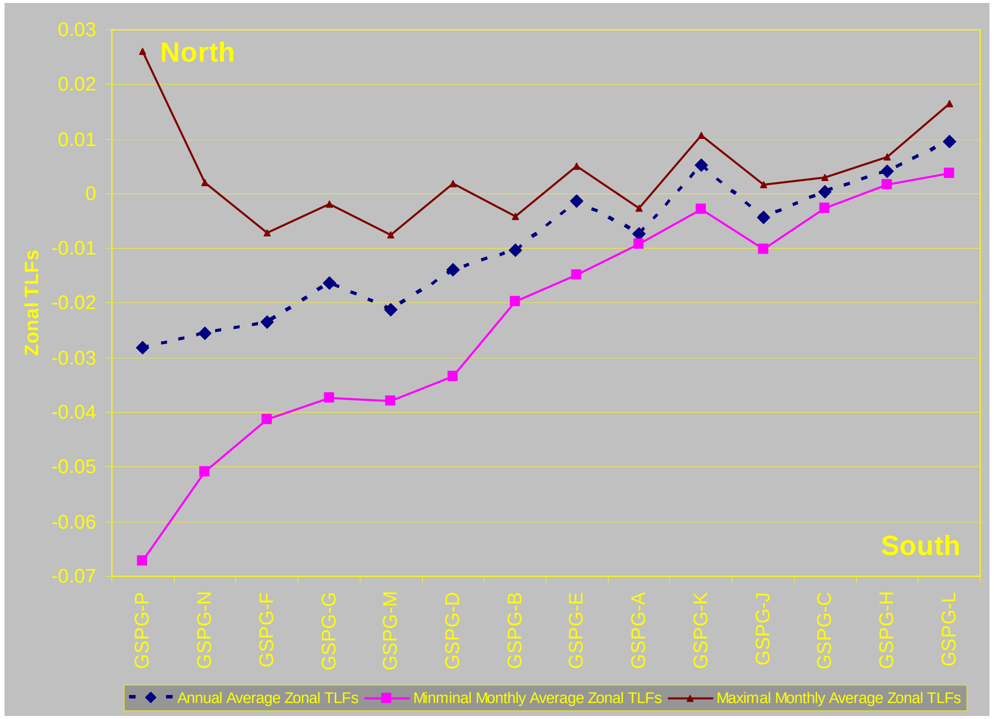


Figure 27: Envelope of variations of Adjusted Daily Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs

There is a greater variability of Adjusted Daily Average Zonal TLFs in the north than in the south.

Figure 28, **Figure 30**, **Figure 32**. and **Figure 34** present the relevant Adjusted Daily Average Zonal TLFs for spring, summer, autumn and winter representative days respectively and compared to the corresponding Adjusted Seasonal Average Zonal TLFs. **Figure 29**, **Figure 31**, **Figure 33**, and **Figure 35** present the envelope of variations of Adjusted Daily Average Zonal TLFs for spring, summer, autumn and winter representative days respectively, around the corresponding Adjusted Seasonal Average Zonal TLFs. Note that the envelope lines are not coincident with any daily line and also that these seasonal and daily values were derived from different sample data sets (thus the cases seasonal values breaking through the envelopes)! These figures demonstrate that the Adjusted Seasonal Average Zonal TLFs have a potential to represent Adjusted Daily Average Zonal TLFs (of corresponding seasonal days) somewhat better that the Adjusted Annual Average Zonal TLFs (as in **Figure 27**).

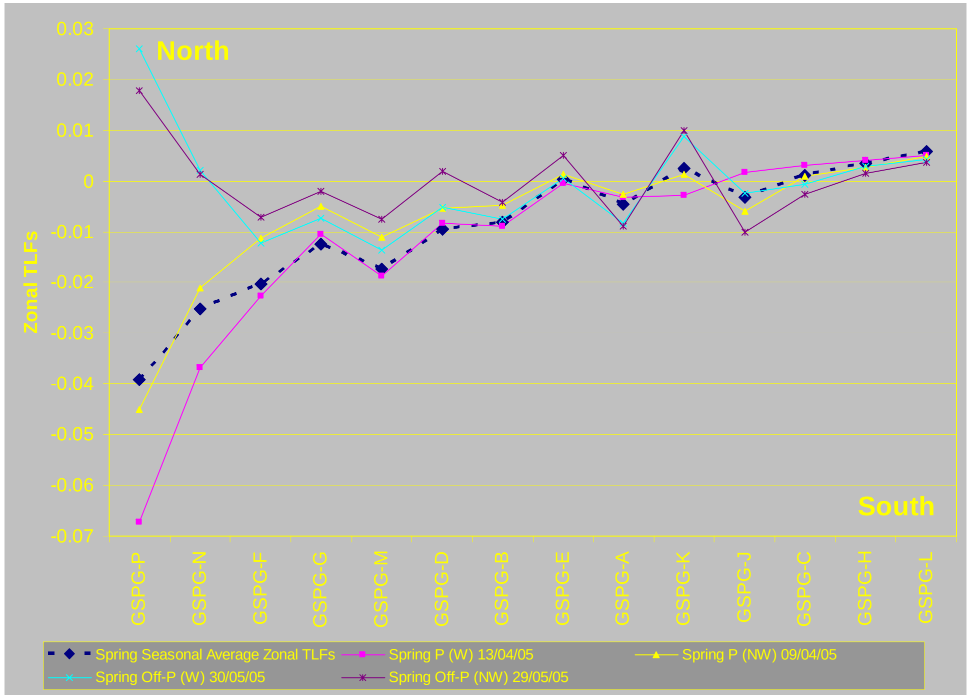


Figure 28: Adjusted Daily Average Zonal TLFs for spring months compared to the Spring Adjusted Seasonal Average Zonal TLFs

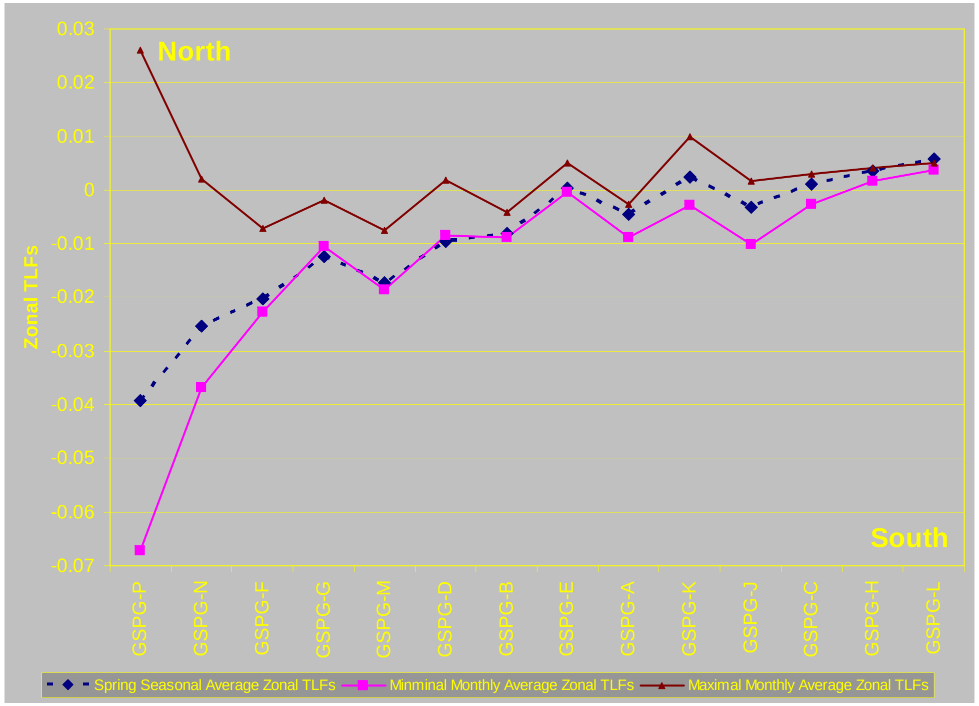


Figure 29: Envelope of variations of Adjusted Daily Average Zonal TLFs for spring months around the Spring Adj. Seasonal Average Zonal TLFs

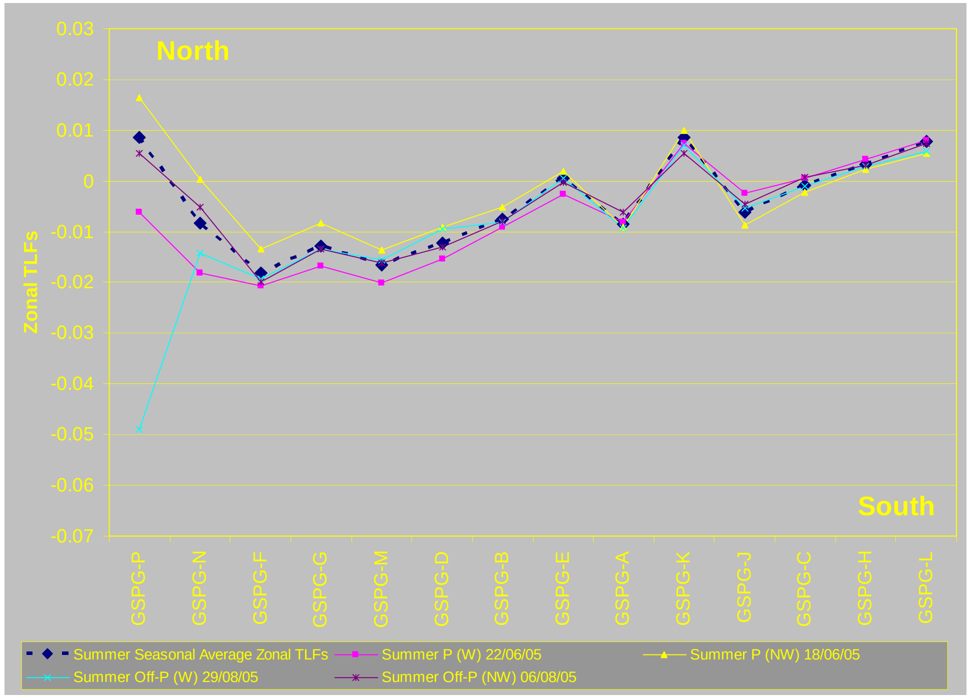


Figure 30: Adjusted Daily Average Zonal TLFs for summer months compared to the Summer Adjusted Seasonal Average Zonal TLFs

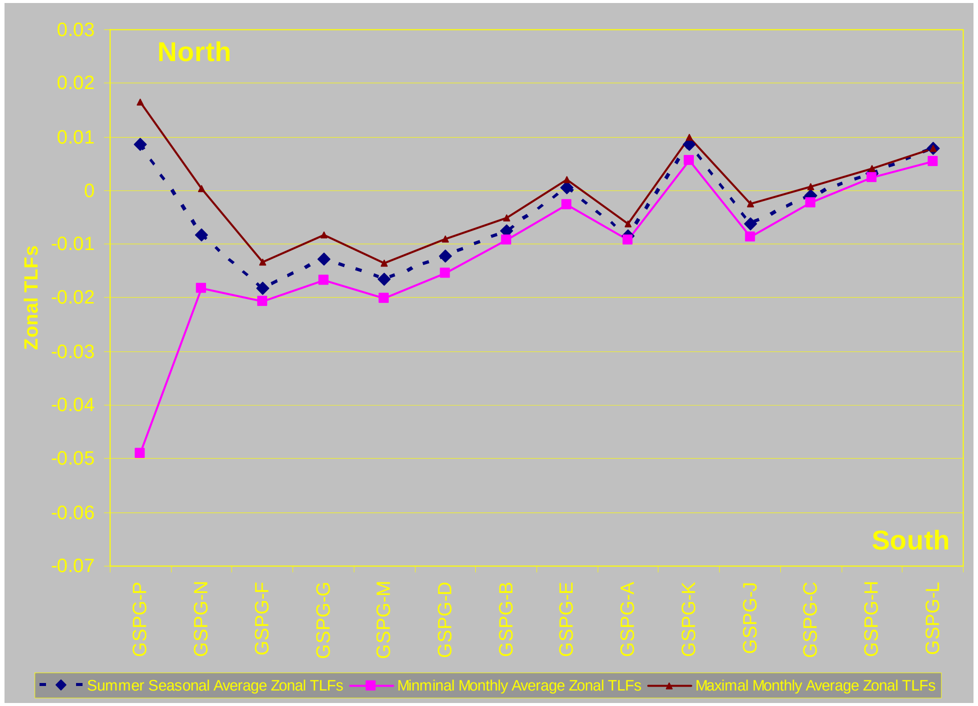


Figure 31: Envelope of variations of Adjusted Daily Average Zonal TLFs for summer months around the Summer Adj. Seasonal Average Zonal TLFs

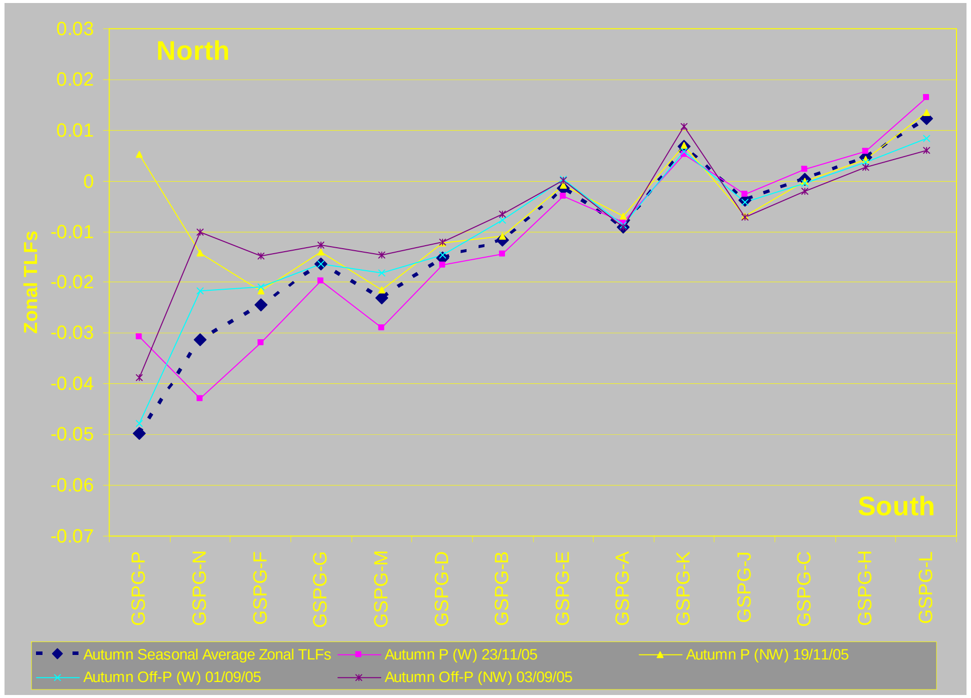


Figure 32: Adjusted Daily Average Zonal TLFs for autumn months compared to the Autumn Adjusted Seasonal Average Zonal TLFs

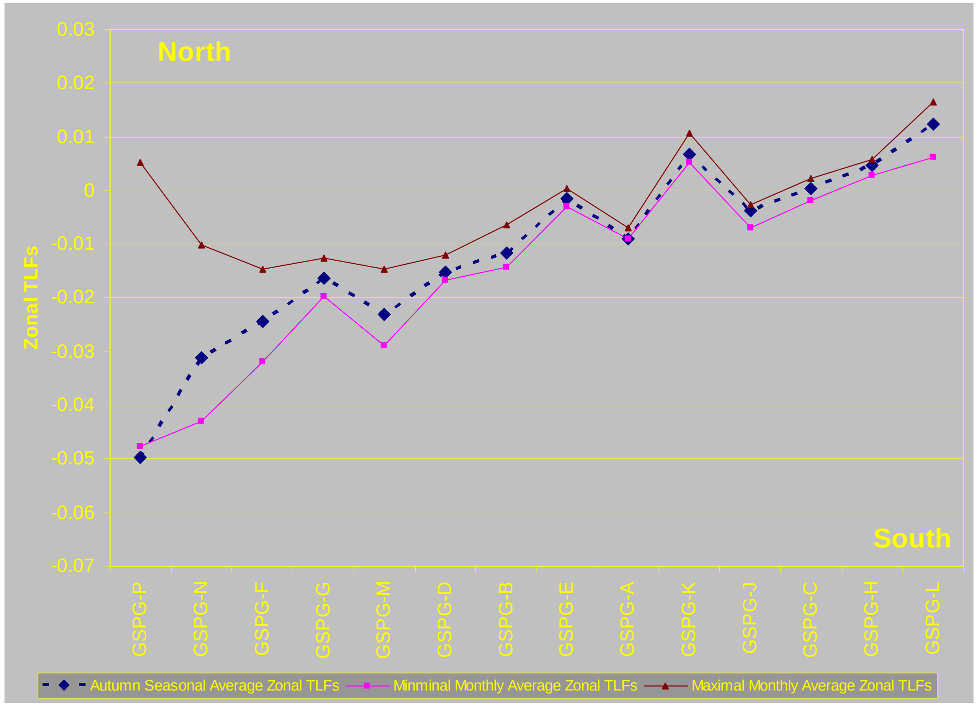


Figure 33: Envelope of variations of Adjusted Daily Average Zonal TLFs for autumn months around the Autumn Adj. Seasonal Average Zonal TLFs

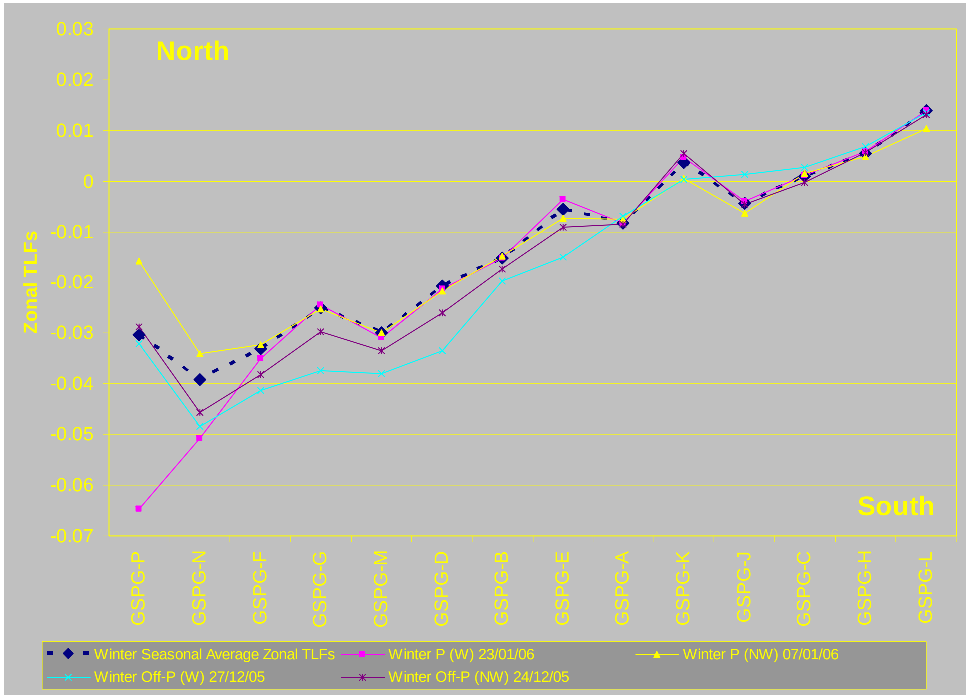


Figure 34: Adjusted Daily Average Zonal TLFs for winter months compared to the Winter Adjusted Seasonal Average Zonal TLFs

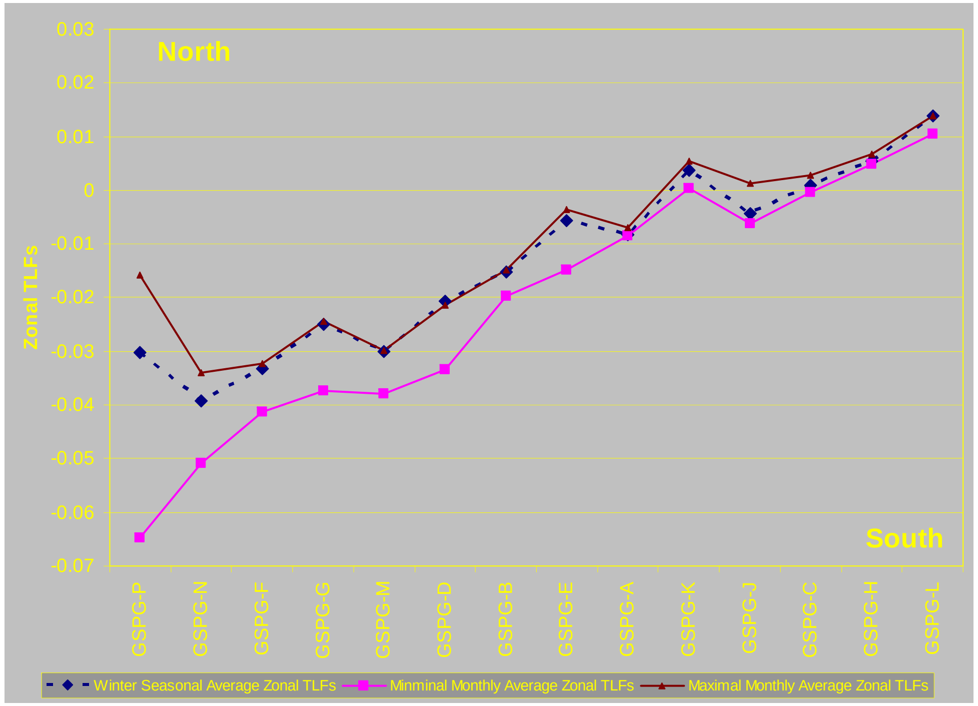
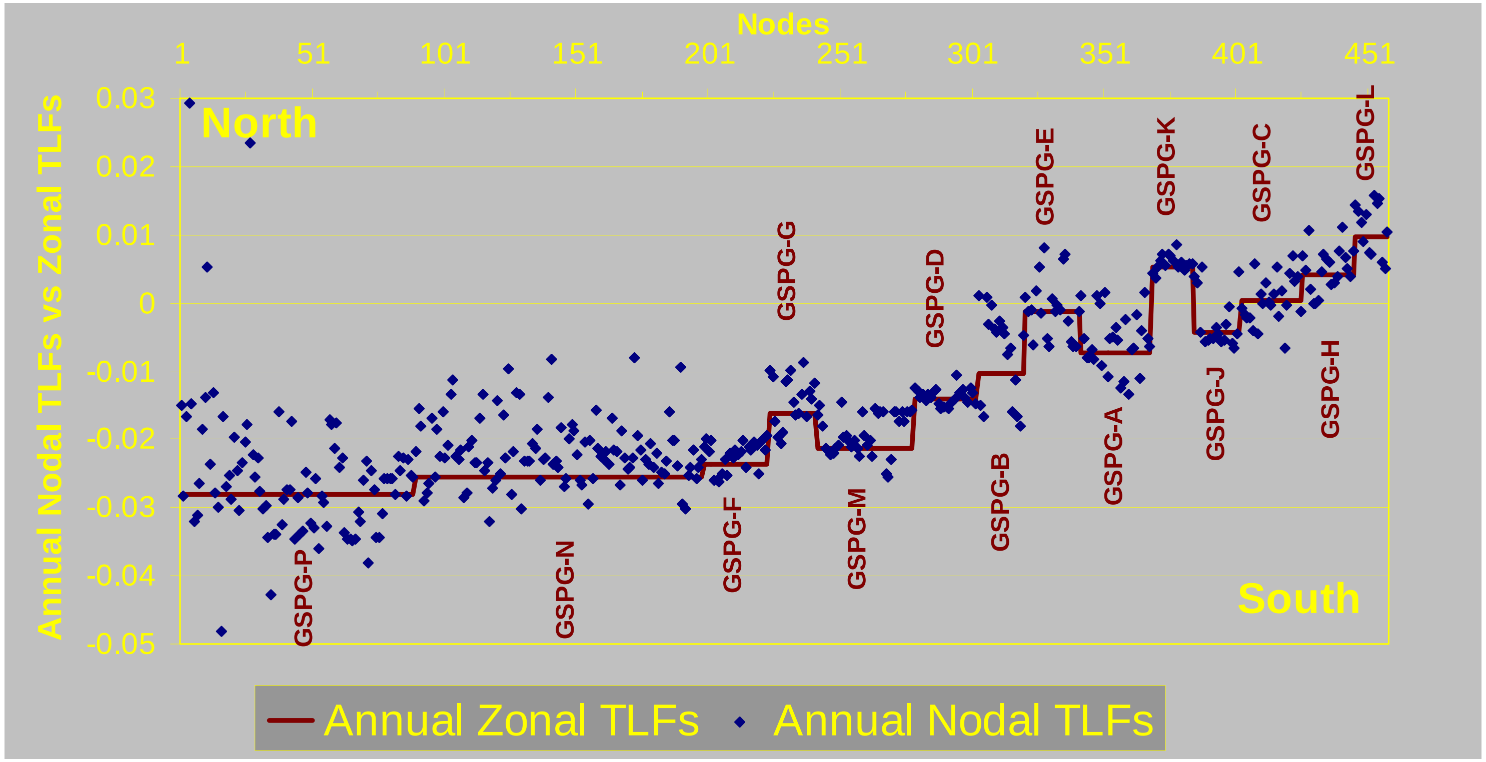


Figure 35: Envelope of variations of Adjusted Daily Average Zonal TLFs for winter months around the Winter Adj. Seasonal Average Zonal TLFs

5.4 Task 3: Compare Annual Average Nodal TLFs to Annual Average Zonal TLFs



This task was set to compare Adjusted Annual Average Nodal TLFs with Adjusted Annual Average Zonal TLFs with the objective to examine how well Zonal TLFs represent nodal TLFs. In this comparison the baseline Adjusted Annual Average Zonal TLFs (from Task 1) were used. The Adjusted Annual Average Nodal TLFs were derived from the same baseline input/output data, using the same time weighted averaging as for the Annual Average Zonal TLFs.

Figure 36: Comparison of Adjusted Annual Average Nodal TLFs to Adjusted Annual Average Zonal TLFs

Figure 36 presents comparison of Adjusted Annual Average Nodal TLFs to Adjusted Annual Average Zonal TLFs. Note that Adjusted Annual Average Zonal TLFs in **Figure 36** were not derived directly from respective Adjusted Annual Average Nodal TLFs. Adjusted Annual Average Nodal/Zonal TLFs were derived from ½ h nodal/zonal TLFs respectively.

From the results it can be observed that introduction of Modification Proposal P198 and its Zonal TLMs (GSPG zones) could result in nodal TLFs for some nodes being closer to neighbouring zonal TLFs.

Adjusted Annual Average Nodal TLFs for some nodes are closer to neighbouring Adjusted Annual Average Zonal TLFs.

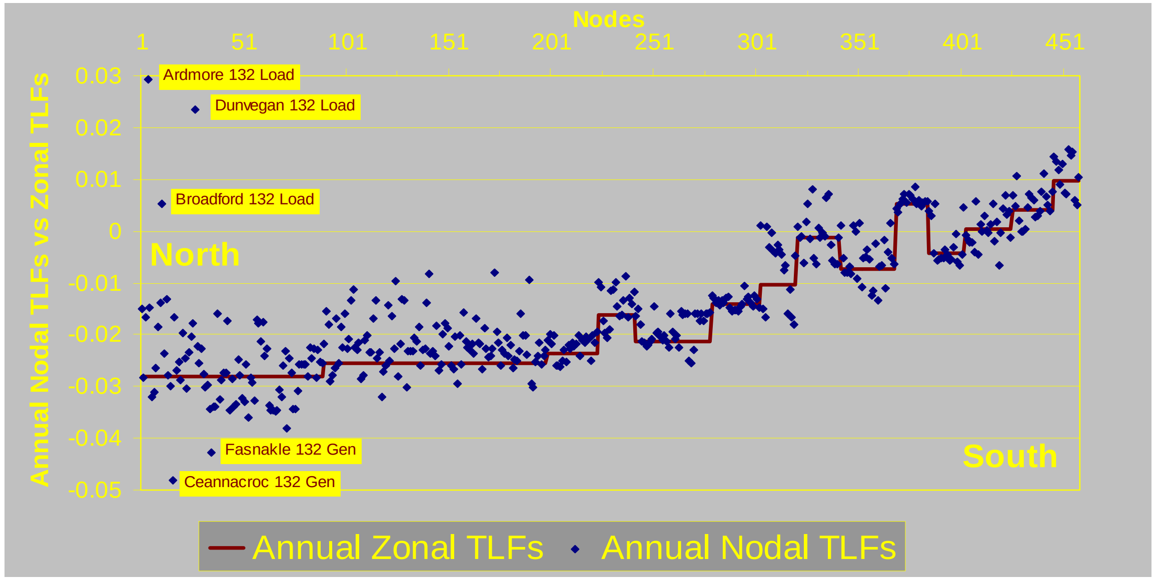


Figure 37: Comparison of Adjusted Annual Average Nodal TLFs to Adjusted Annual Average Zonal TLFs where 5 outliers in GSPG-P zone are identified (load or generation are attributed as predominant characteristics of these nodes)

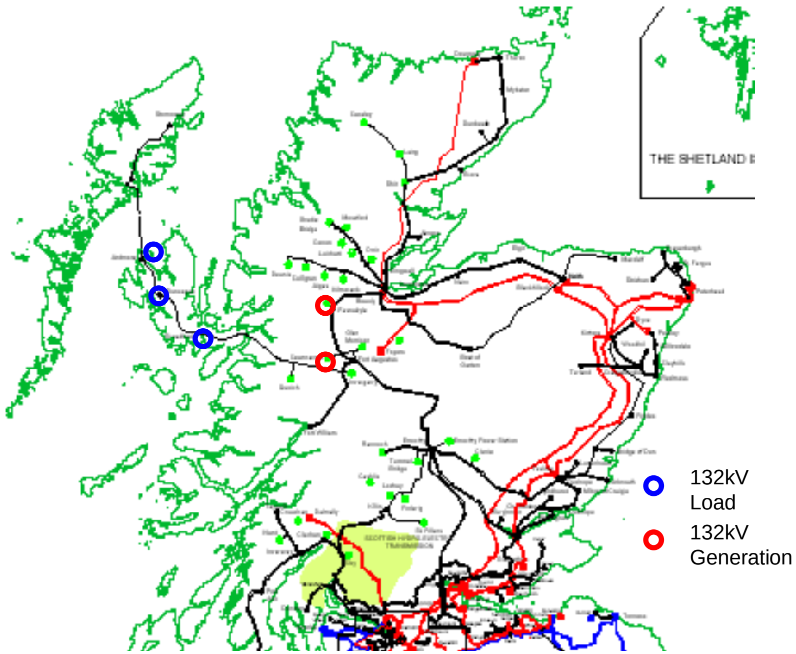


Figure 38: Geographical locations of the nodes considered in GSPG-P and identifies in Figure 37

In **Figure 36** there are 5 nodes in GSPG-P zone noted as outliers. Further investigation was made to understand better this phenomenon. These considered nodes are identified in **Figure 37** where their predominant characteristic, in terms of generation or load, is also marked. Initially it seemed at odds with the intuitive expectation that the identified loads in north Scotland would be contributing to the system heating losses and thus attracting the corresponding TLF signals.
The geographical location of the 5 nodes considered is identified in **Figure 38**. It is the “electrical location” in the transmission system that is one of the main factors influencing the TLFs, however, this is often well correlated to the geographical location. The 3 load nodes are in a quite remote area connected over long 132kV network, while the 2 generation nodes are exporting over the 132 kV network from the area that is still relatively remote. In such a situation delivering/offtaking at these nodes contribute to increasing total system heating losses, what is then reflected in their TLFs. Therefore, with such an insight the Adjusted Annual Average Nodal TLFs for these 5 nodes becomes compatible with the intuitive expectations.

In support of the above findings another test was performed, where the calculations were performed with 132 kV network excluded from calculations of heating losses. In a way, this brought the nodes in Scotland much closer, in electrical terms, to each other and also somewhat closer to the rest of the nodes in the GB transmission system. **Figure 39**, particularly in comparison with **Figure 36** or **Figure 37**, clearly demonstrates the effect of 132 kV network and the losses on this network on the

Adjusted Annual Average Nodal TLFs as presented in **Figure 36** and **Figure 37**. **Table 5** presents comparative Adjusted Annual Average Nodal TLF figures for the 5 nodes considered.

In the findings described above the main influences are of a predominantly local character. However, the fact that all the influences do spread across the entire GB transmission network, though to a different extent, should not be overlooked.

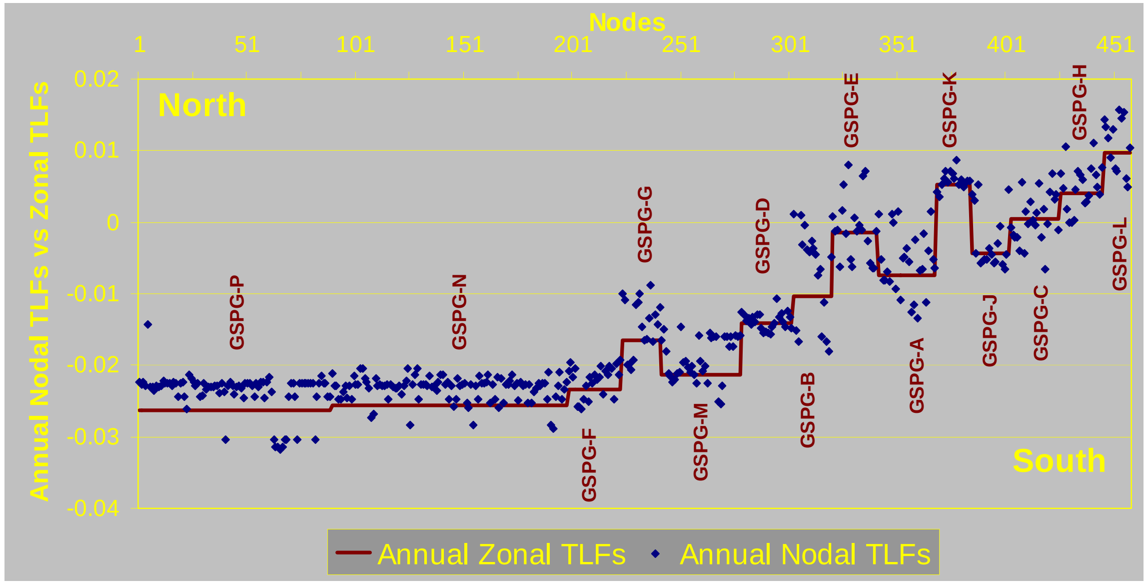


Figure 39: Comparison of Adjusted Annual Average Nodal TLFs to Adjusted Annual Average Zonal TLFs when 132kV network (Scotland) is excluded from calculation of losses

Table 5: Adjusted Annual Average Nodal TLFs for the five considered nodes (when 132kV network losses were and when they weren't included in the calculations)

Node	Annual Nodal TLF with 132kV losses	Type	Name	Annual Nodal TLF without 132kV losses
ARMO30	0.02923943	Load	Ardmore 132	-0.02287918
BROA30	0.0053289	Load	Broadford 132	-0.02287921
CEAN30	-0.04814187	Gen	Ceannacroc 132	-0.02287928
DUGR30	0.02356373	Load	Dunvegan 132	-0.02287919
FASN30	-0.04288179	Gen	Fasnakle 132	-0.02295488

5.5 Task 4: Establish the degree to which a scaling factor of 0.5 recovers the heating losses

5.5.1 Task 4: Introduction

The Transmission Loss Factors (TLFs) are sensitivity coefficients. Sensitivity coefficients obtained by the method applied are Nodal TLFs (as with any other marginal method). A particular Nodal TLF indicates the rate of change in the total system heating losses due to a marginal change in Nodal Power Flow (also known as nodal power injection) at that node. When such a Nodal TLF is multiplied by the Nodal Power Flow at that node (while observing the adopted sign convention) the outcome is a contribution of the Nodal Power Flow at that node to the total system heating losses. This is valid for a particular network configuration, and the Nodal Power Flows at a particular time. This contribution of a particular node and its Nodal power Flow to the total system heating losses can be contributing to increasing or decreasing these losses. However, due to the mathematical characteristics of the system the sum of these contributions over all the nodes in the system returns an amount of losses about twice the physical/calculated total system heating losses. In recognition of this natural model/physical characteristic, usually TLFs are adjusted by a scaling factor. This scaling factor is normally around 0.5 and its intention is that Adjusted Nodal TLFs would then recover exactly the total system heating losses. It is known that using AC modelling would require scaling factors that would with time (as system conditions change – primarily Nodal Power Flows) slightly vary around 0.5. This task was set to indicate how good a fixed 0.5 scaling factor is for the DC model applied.

5.5.2 Task 4: Results – TLFs and the scaling factor

For the purpose of this Task, the baseline case from Task 1 was re-run with a modification. In Task 1 the scaling factor of 0.5 was applied at the last step of the calculations, i.e. to the Annual Average Zonal TLFs in order to obtain the Adjusted Annual Average Zonal TLFs. Here, in Task 4 for each SSP the Nodal TLFs were scaled by a scaling factor specially calculated for each SSP in order to obtain Adjusted Nodal TLFs for that particular SSP. Further averaging was conducted in the same was as in Task 1. At the end there was no need to scale the Annual Average Zonal TLFs as there were inherently adjusted and directly comparable to the Adjusted Annual Average Zonal TLFs from Task 1. The scaling factors specially calculated for each SSP were such that the Adjusted Nodal TLFs for individual SSP were recovering the exact calculated system heating losses. These 623 SSP Scaling Factors were recorded. **Table 6** presents basic statistical information on these 623 SSP Scaling Factors.

Table 6: Scaling Factors calculated for each SSP

	SSP Scaling Factors
Max	0.5001012
Min	0.4999952
Average	**0.5000371**
SD	0.000024

From the results obtained it can be concluded that they demonstrate that the correct scaling factor is 0.5. It should be noted that the employed method for calculation of TLFs is based on DC load flow which is a linearised model. The figures obtained (**Table 6**) can be understood to reflect a negligible numerical noise from the calculations performed. The (Adjusted) Annual Average Zonal TLFs in Task 4 are the same as the Baseline Adjusted Annual Average Zonal TLFs in Task 1.

Task 4 results empirically confirmed that the scaling factor of 0.5 is correct choice for the method applied.

5.5.3 Task 4: Results – Losses calculated from the Annual Average Zonal TLFs (recovery of losses)

In respect of these results Task 1 and Task 4 are well in agreement (putting a negligible numerical noise aside). However, the results are of possible particular interest from a broader perspective.

The total Metered Volume Losses (obtained from the Metered Volumes directly) for all 623 SSP were 272,107.1MWh (these losses include the fixed losses as well as possible recording errors). The total calculated system heating losses (for all 623 SSP) were 125,549.2MWh. It is expected that the total calculated system heating losses plus the total of fixed losses broadly match the total Metered Volume Losses. However, taking into account a pretty broad estimate for fixed losses to be between 70,000MWh and 90,000MWh in total for these 623 SSP, there would be still some gap (of about 70,000MWh to 80,000MWh) between the total calculated losses and Metered Volume Losses that is not accounted for (**Table 7**).

Normally, it is expected that the calculated recovery of losses using the adjusted TLFs match the total calculated system heating losses. The initially agreed method to calculate the recovery of losses was to apply the AAA Zonal TLFs to the corresponding Metered Volumes. In such a way the total recovered losses over 623 SSP were 44,174MWh (**Table 8**). This figure stands in sharp contrast to the above Total Metered Volume Losses as well as to the total calculated losses.

Nodal TLFs (for each SSP) are calculated on the basis of Net Nodal Power Flows (for the corresponding SSP). The Nodal Power Flows are derived from the Metered Volumes in such a way that they do not reflect any losses (real or due to recording problems). The losses are calculated subsequently from the flows on the transmission network, as well as the SSP Nodal TLFs. In that way Net Nodal Power Flows, calculated system heating losses and SSP Nodal TLFs are completely consistent. In order to examine further the Adjusted Annual Average Zonal TLFs and averaging methods adopted, the recovery of losses were also calculated by applying the Adjusted Annual Average Zonal TLFs to the corresponding Net Nodal Power Flows. In such a way the total recovered losses over 623 SSP were 41,268MWh (**Table 8**). This figure, too, stands in sharp contrast to the above Total Metered Volume Losses as well as to the total calculated losses.

It should be noted that recovered losses are expected to match the calculated heating losses as they are the basis for calculating the TLFs. Using Adjusted Nodal TLFs for particular SSPs applied to the Net Nodal Power Flows would return recovered losses equal to the calculated heating losses precisely. Due to the characteristics of the averaging process in obtaining the Adjusted Average Annual Zonal TLFs (in particular the time-weighted averaging component) they can not be expected to return recovered losses equal to the calculated heating losses precisely. However, intuitively they would be expected to return a relatively close value, but in any case, for the purpose of calculating TLMs, it is expected that relative differentials between the Adjusted Average Annual Zonal TLFs correctly reflect the signals coming from the fundamental marginal method applied.

Table 7: Comparison of Metered Volume Losses and Calculated Heating Losses

Values across 623 SSPs	
Total Metered Volume losses	272,107 MWh
Total calculated heating losses	125,549.2 MWh
Estimated fixed losses	70,000 MWh to 90,000 MWh
Unaccounted quantity (estimation)	70,000 MWh to 80,000 MWh

Table 8: Recovered losses using Adjusted Annual Average Zonal TLFs

Values across 623 SSPs	
Total Metered Volume losses	272,107 MWh
Total calculated heating losses	125,549.2 MWh
Recovered losses	
Adjusted Annual Average Zonal TLFs applied on Metered Volumes	44,174 MWh
Adjusted Annual Average Zonal TLFs applied on Net Nodal Power Flows	41,268 MWh

5.5.4 Task 4: Explanatory note on – Losses calculated from the Annual Average Zonal TLFs (recovery of losses)

The sources of the noted discrepancy

- between the Metered Volume Losses and recovery of losses obtained by application of the Adjusted Annual Average Zonal TLFs to the Metered Volumes; and
- between the calculated heating losses and recovery of losses obtained by application of the Adjusted Annual Average Zonal TLFs to the Net Nodal Power Flows

are identified as follows:

5.5.4.1 Metered Volumes and Nodal Power Flows

The applied method uses the Nodal Power Flows in calculation of TLFs. Nodal Power Flows are derived from the Metered Volumes, but they are not the same.

Any problems in consistency and accuracy of the Metered Volumes would only further exaggerate the noted discrepancy problem. **Table 7** presents the potential problem noted with the input data used for the Metered Volumes. ELEXON performed an analysis of the sample sets used for P82 2003 live calculations, and for P198 2006 modelling, and of the corresponding set of BMU 2006 data. The findings, in terms of the level of observed losses are presented in **Figure 40**. While losses derived from BMU 2006 data are broadly in line with the expectations (based from other analyses of the GB transmission system operations), the losses derived from the other two sets are:

- Notably higher than expected; and
- "Noise" around average of data sets for P82 2003 live calculations, and for P198 2006 modelling is much larger and irregular than "noise" around average of the corresponding set of BMU 2006 data.

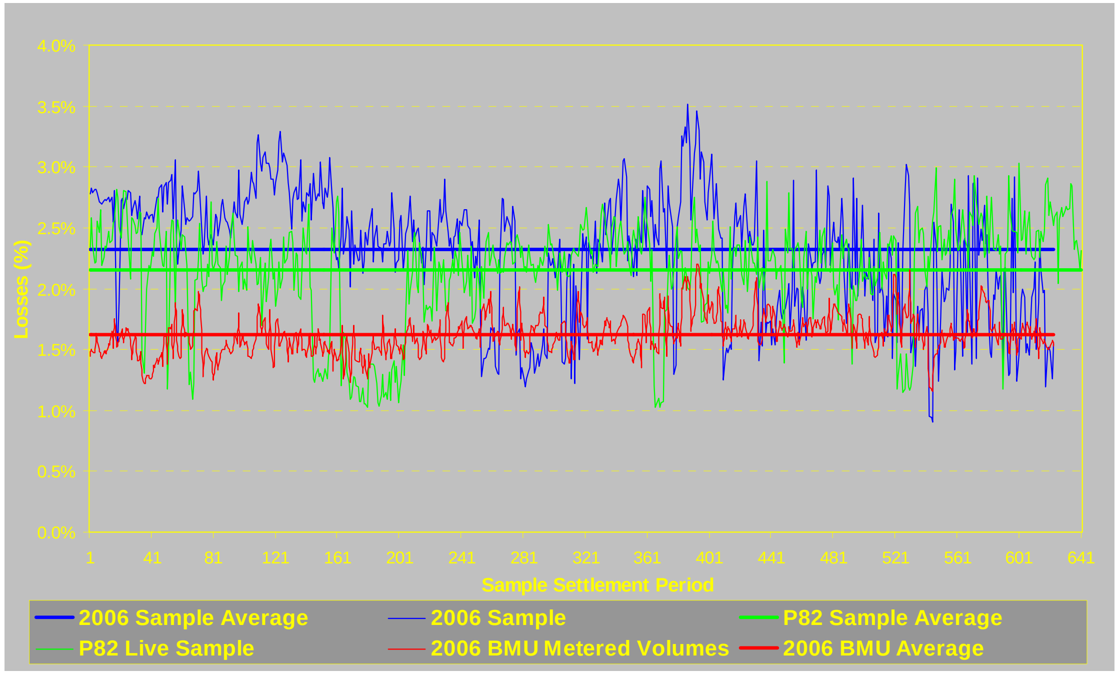


Figure 40: Comparison of losses observed on 2003 P82 Live and 2006 Modelling Sample Sets and on 2006 BMU Data for the corresponding SSPs (ELEXON)

Since the issue was observed in both the P82 and P198 data sample it is considered to be related to the sample definition. ELEXON identified a potential source of the discrepancy as the approach used to aggregate metered data for certain GSPs. It may be that for a small subset of GSPs which feed two GSP Groups the aggregated metered data does not reflect the total flow of electricity from the Transmission System. At a shared GSP, only the flow into the primary GSP Group is included in the GSP Metered Data, the secondary flow is reflected in the relevant GSP Group Take (and hence not reflected in the Load Flow modelling sample). Investigations are ongoing to establish whether there is a feasible method to account for the discrepancy in live operation.

It should be noted that

- The TLF calculations are based on Nodal Power Flows that are derived from Metered Volumes in such a way that any losses are initially eliminated. The losses are then calculated from the flows on the transmission network. In that way the problem with the Meter Volume Losses does not influence the calculated TLFs directly and to full extent.
- There may be some influence on the nodal power flows across the sample.
- The impact on Nodal TLFs for a particular node may be more significant. However this is unlikely to have a significant impact on Adjusted Annual Average Zonal TLFs, due to zonal averaging.
- Overall it is not considered that the influence on the results of the modelling materially affect the conclusion that can be drawn.

5.5.4.2 Calculation of Zonal TLFs for a particular SSP

The approach adopted for calculation of Zonal TLFs for a particular SSP (a particular volume-weighted averaging) produces such Zonal TLFs that a Zonal TLF does not recover the same losses as the Nodal TLFs recover in the same zone. This is another, strong factor contributing to the noted discrepancy issue.

More on this issue is presented in Section 6.

Consideration of this issue led to examining an alternative method for calculation of Zonal TLFs for a particular SSP, where Delivering and Offtaking Zonal TLFs are distinguished (Section 6 and Section 6.1). Derived Alternative Adjusted Annual Average Delivering and Offtaking Zonal TLFs when applied on net Nodal Power Flows return recovered losses much closer to calculated heating losses than current Adjusted Annual Average Zonal TLFs (**Table 20** from Section 6.1, presenting these recovered losses, is repeated here as **Table 9** for convenience). As the Alternative SSP Delivering and Offtaking Zonal TLFs recover losses that exactly equal to the calculated losses for that SSP, the discrepancy between **108,328 MWh** and **125,549.2 MWh** (**Table 9**) is attributable to influence of the time-weighted averaging.

Table 9: Comparison of the recovered losses when using current AAA Zonal TLFs and when using Alternative AAA Delivering and Offtaking Zonal TLFs

Values across 623 SSPs	
Total calculated heating losses	125,549.2 MWh
Recovered losses	
Adjusted Annual Average Zonal TLFs applied on Net Nodal Power Flows	41,268 MWh
Alternative Adjusted Annual Average Delivering and Off-taking Zonal TLFs applied on corresponding Net Nodal Power Flows	108,328 MWh

5.5.4.3 Calculation of Annual Average Zonal TLFs

This is a time weighted averaging and as such it has a potential to contribute to the noted discrepancy problems. However, under the circumstances it was not possible to determine if there was such an influence and to what extent.

5.6 Task 5: Consider impact of utilising an Intact Network

For the purpose of this task the Metered Volumes for the 623 SSPs from Task 1 were divided into four seasons and each season was coupled with the appropriate network (provided by National Grid). For the winter season the Intact Network was used and the other three seasons three representative networks were used.

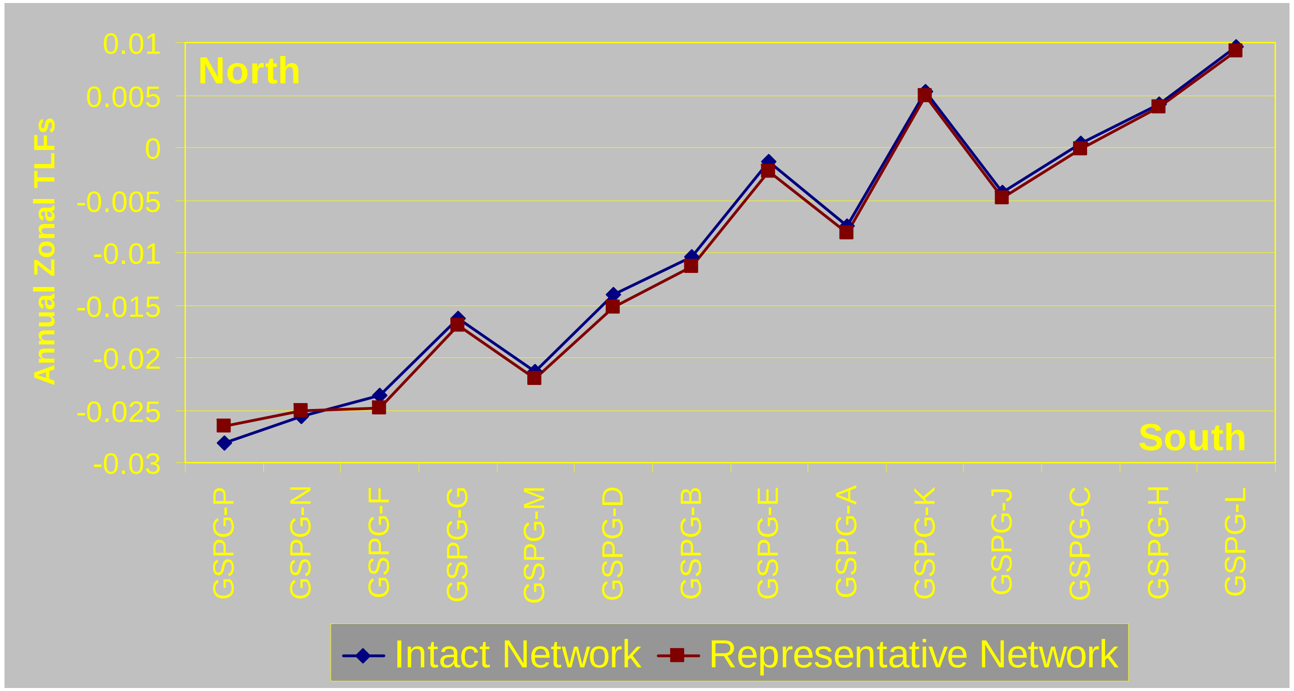


Figure 41: Comparison of Adjusted Annual Average TLFs when calculated using the Intact Network (Task 1) and when using the set of Representative Networks

Table 10: Adjusted Annual Average Zonal TLFs for Intact Network case and for the case of using a set of Representative Networks

	AAA Zonal TLFs	
Zone	Intact Network	The set of Representative Networks
GSPG-P	-0.02818	-0.02653
GSPG-N	-0.02561	-0.02513
GSPG-F	-0.02355	-0.02474
GSPG-G	-0.01625	-0.01694
GSPG-M	-0.02127	-0.02196
GSPG-D	-0.01399	-0.01516
GSPG-B	-0.01038	-0.01131
GSPG-E	-0.00133	-0.00221
GSPG-A	-0.00742	-0.00809
GSPG-K	0.0053	0.00499
GSPG-J	-0.0043	-0.00477
GSPG-C	0.00039	-0.00015
GSPG-H	0.00414	0.00384
GSPG-L	0.00963	0.00922

Network configuration can have an effect on Adjusted Annual Average Zonal TLFs.

Illustrative Delivery and Off-taking Zonal TLMs for peak SP and trough SP calculated on the basis of the Adjusted Annual Average Zonal TLFs for the Representative Seasonal Networks are presented in **Figure 42** and **Figure 43**. These TLMs are compared to Delivery and Off-taking Zonal TLMs (for the same SPs) calculated on the basis of the Adjusted Annual Average Zonal TLFs for the Intact Network.

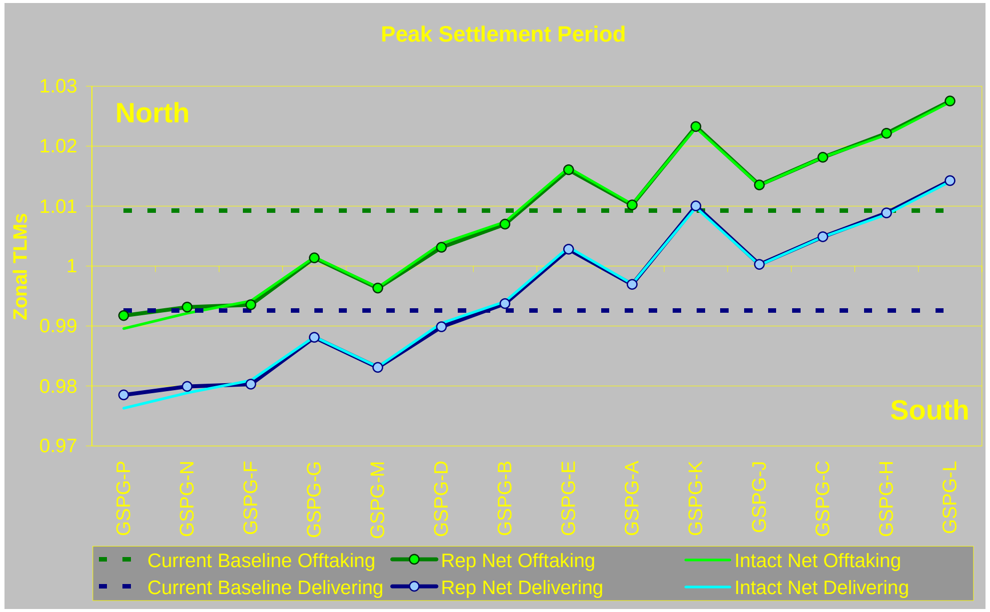


Figure 42: Delivery and Off-taking Zonal TLMs for peak SP based on a set of Representative seasonal networks and compared to Delivery and Off-taking Zonal TLMs based on the Intact Network (for the same SP); current TLMs (based on TLF = 0) are also presented for this SP

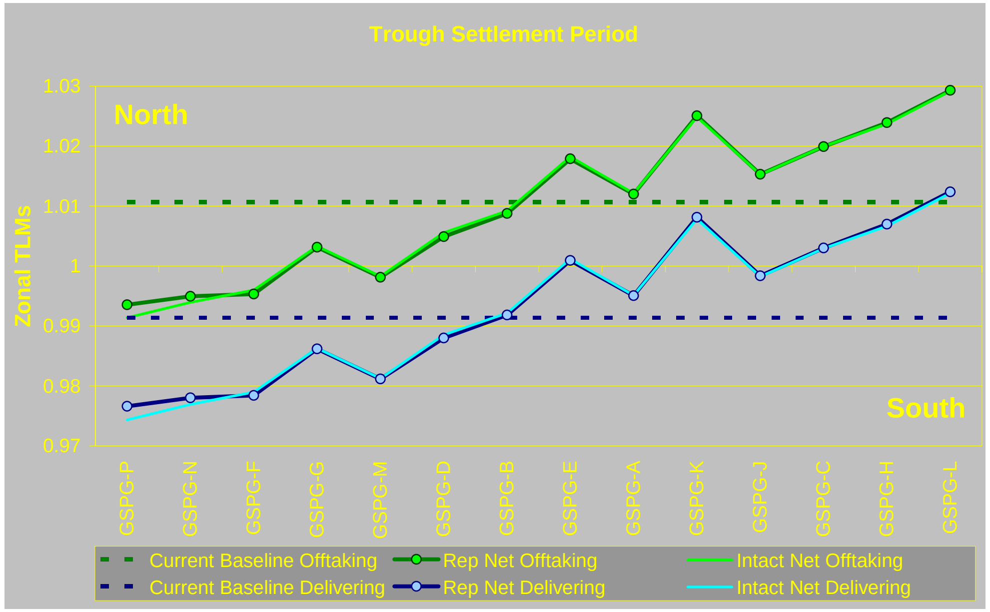


Figure 43: Delivery and Off-taking Zonal TLMs for trough SP based on a set of Representative seasonal networks and compared to Delivery and Off-taking Zonal TLMs based on the Intact Network (for the same SP); current TLMs (based on TLF = 0) are also presented for this SP

5.7 Task 6: Examine sensitivity to constraints

A Settlement Period was identified when there was a constraint influencing the deliveries, off-takes and power flows in the system. The constrained network was representative of transfers across the circuits between Scotland and England in September 2005, where power flows across the boundary were reduced. Metered Volumes for this SP together with this indicative network were used in the calculations. The Adjusted SSP Zonal TLFs for this case are compared with the Adjusted Annual Average Zonal TLFs in **Figure 44**, and they are compared with Adjusted Zonal TLFs for a similar SSP with normal operational regime and intact network in **Figure 45**.

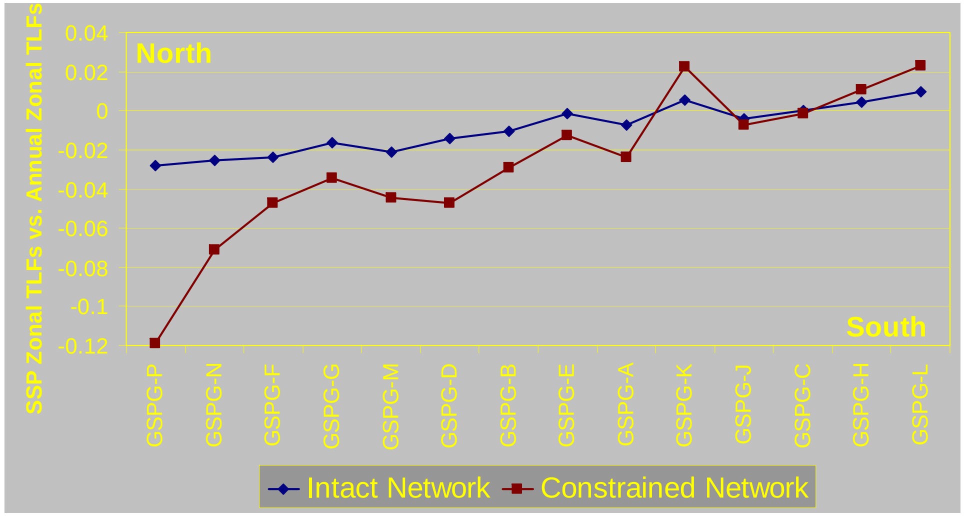


Figure 44: Comparison of Adjusted SSP Zonal TLFs under constraint vs. Adjusted Annual Average Zonal TLFs

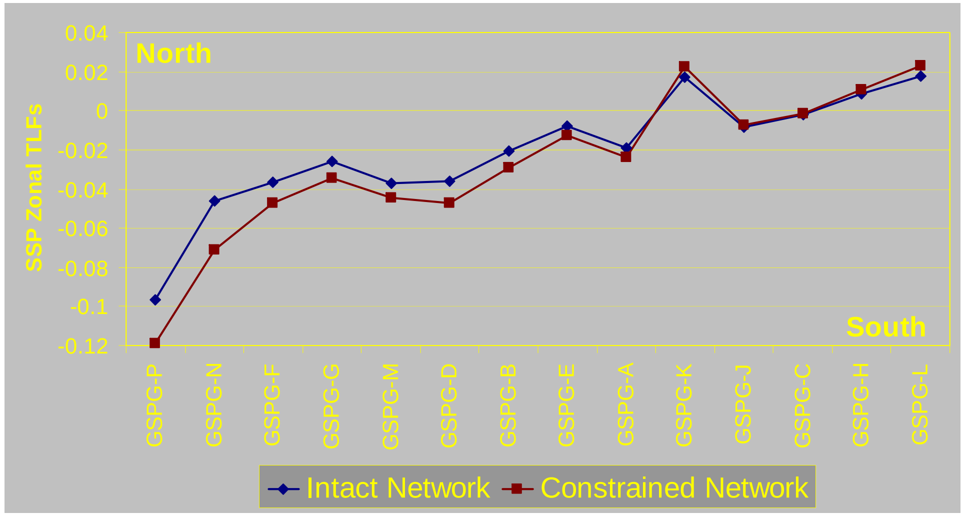


Figure 45: Comparison of Adjusted SSP Zonal TLFs under constraint vs. similar Adjusted SSP Zonal TLFs under Intact Network conditions

Network constraints can have an effect on TLFs.

5.8 Task 7: Examine sensitivity to flows on French and Moyle Interconnectors

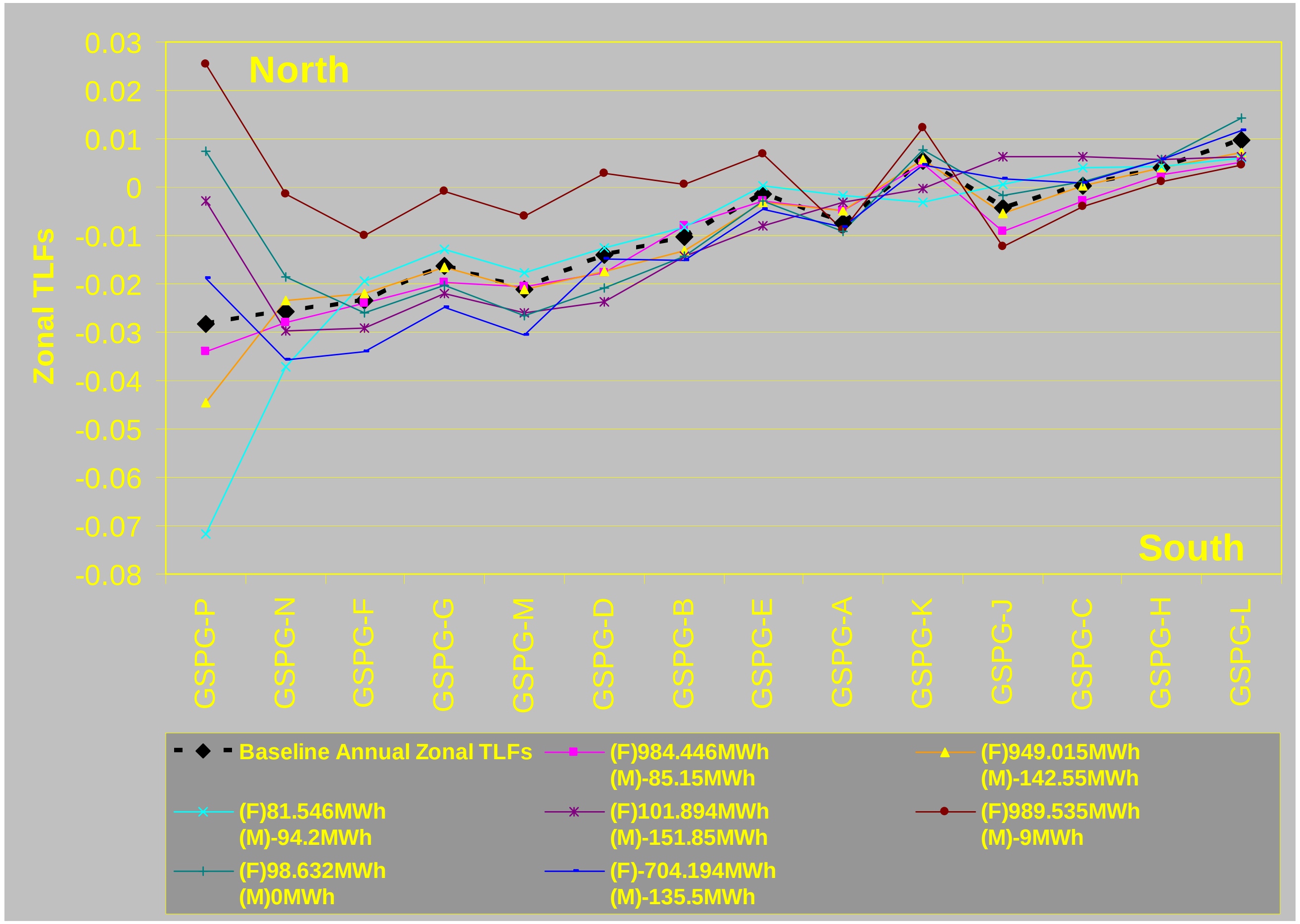


Figure 46: Comparison of Adjusted SSP Zonal TLFs for a number of different operational regimes of the French and Moyle Interconnections put against the baseline Adjusted Annual Average Zonal TLFs

A number of SSP in the Task 1 input/output data set were identified as different indicative operation regimes of the French and Moyle interconnections. It should be noted that a case where Moyle was delivering onto GB system was not available.

Table 11: Different delivery/off-take regimes of the French and Moyle interconnections considered

Interconnection and SSP		Metered Volume MWh	Delivery / Off-take
French	20050401,3	984.446	Delivery
Moyle		-85.15	Off-take
French	20050401,36	949.015	Delivery
Moyle		-142.55	Off-take
French	20050406,17	81.546	Delivery
Moyle		-94.2	Off-take
French	20050517,27	101.894	Delivery
Moyle		-151.85	Off-take
French	20050608,01	989.535	Delivery
Moyle		-9	Off-take
French	20050712,36	98.632	Delivery
Moyle		0	/
French	20060112,12	-704.194	Off-take
Moyle		-135.5	Off-take

Figure 46 presents the Adjusted SSP Zonal TLFs for the different delivery/off take regimes of the French and Moyle interconnections in **Table 11**.

French and Moyle interconnection deliveries/off-takes influence individual SSP Zonal TLFs, but this is averaged over a year.

The Adjusted SSP Zonal TLFs presented in **Figure 46** are classified according to belonging to different seasons and in **Figure 47**, **Figure 48** and **Figure 49** put against respective Spring, Summer and Autumn Adjusted Seasonal Average Zonal TLFs.

In line with the findings in Task 8, Task 10 and Task 11, it can be expected that flows on French and Moyle interconnections influence the Zonal TLFs. However, different arrangements of the flows on French and Moyle interconnections are represented by the Sample Settlement Periods and their influence averaged in the calculation of Adjusted Annual or Seasonal Average Zonal TLFs.

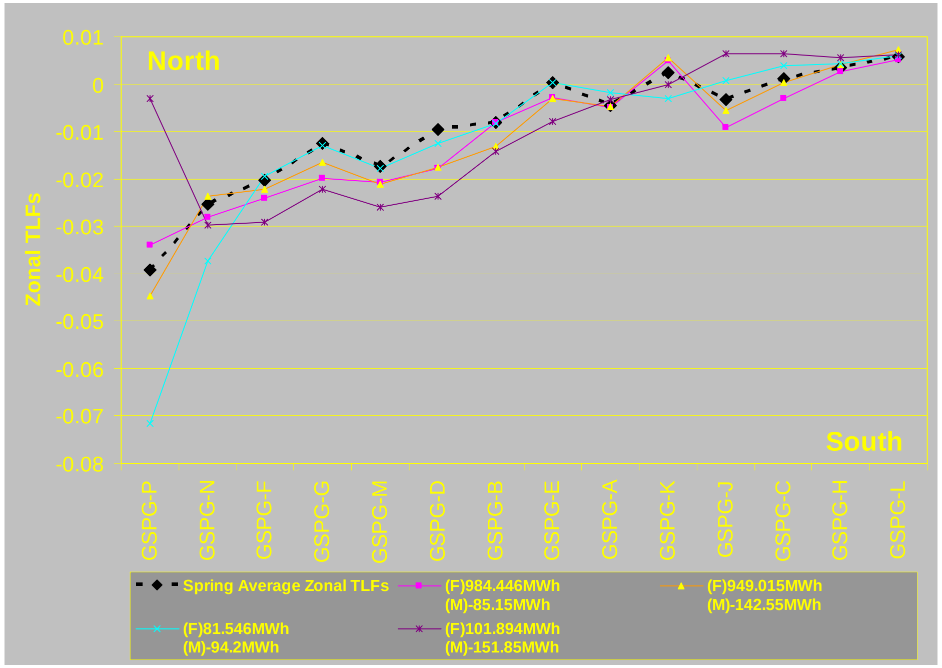


Figure 47: Comparison of Adjusted SSP Zonal TLFs for different operational regimes of the French and Moyle Interconnections put against the Spring Adjusted Seasonal Average Zonal TLFs

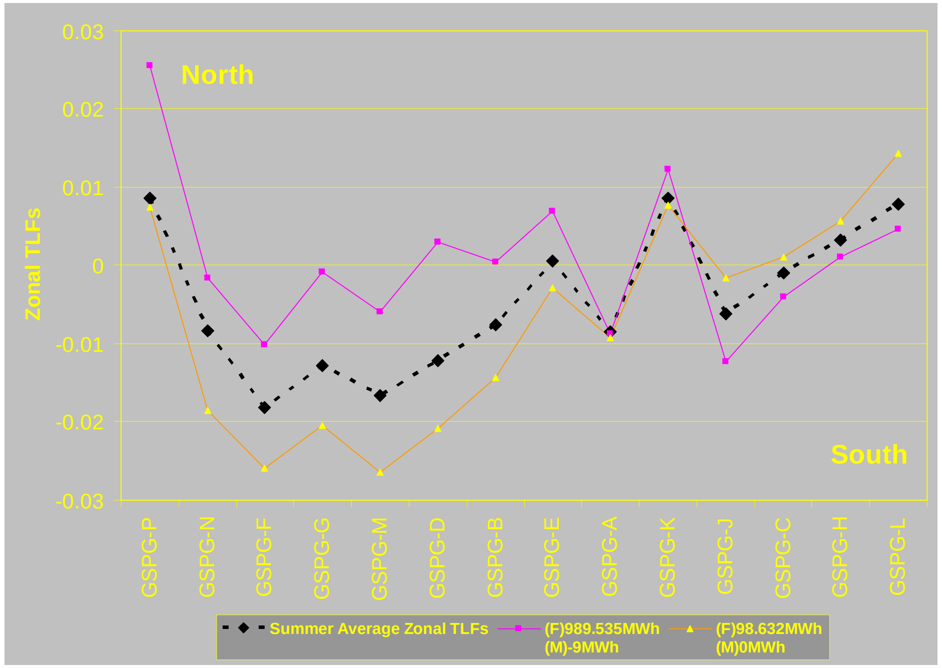


Figure 48: Comparison of Adjusted SSP Zonal TLFs for different operational regimes of the French and Moyle Interconnections put against the Summer Adjusted Seasonal Average Zonal TLFs

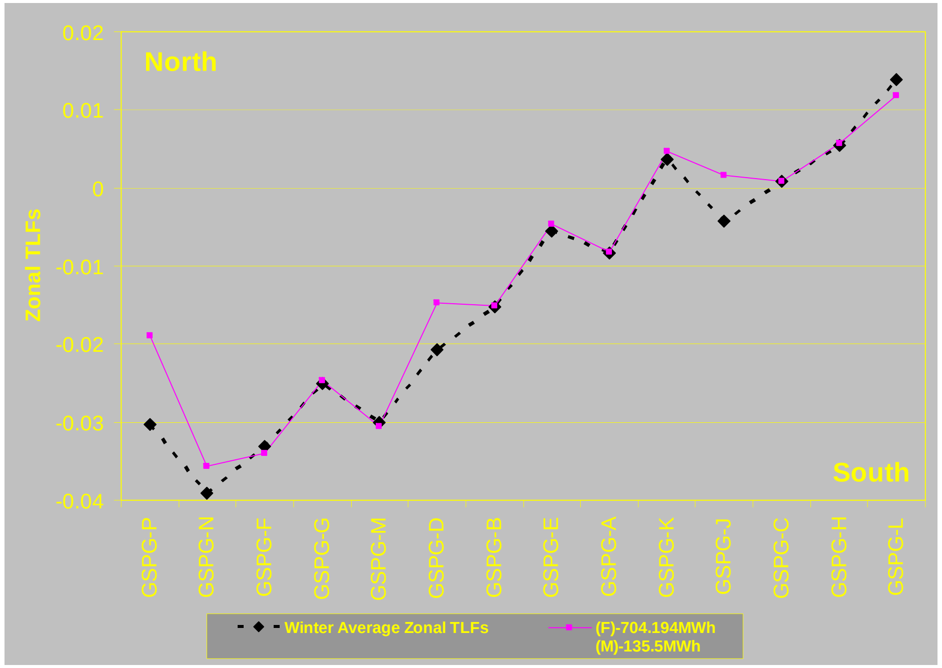


Figure 49: Comparison of Adjusted SSP Zonal TLFs for an operational regime of the French and Moyle Interconnections put against the Winter Adjusted Seasonal Average Zonal TLFs

5.9 Task 8: Examine sensitivity of Annual TLFs to participants responding to signals

In order to model the impact of relocating generation, the output of various BM Units across the 623 SSPs from 3 different locations (thus forming 3 different cases – see **Table 12**) were relocated to the Kingsnorth Node (KINO41/ KINO40). The Adjusted Annual Average Zonal TLFs were calculated for each of the three cases and compared to the baseline Adjusted Annual Average Zonal TLFs

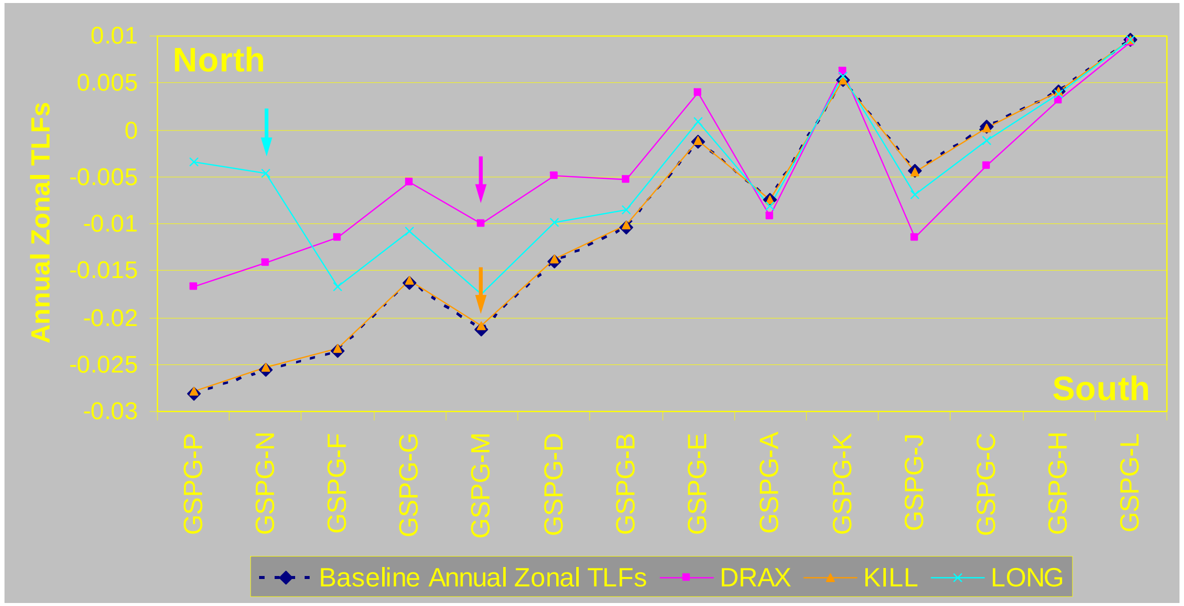


Figure 50: Adjusted Annual Average Zonal TLFs for the four cases of participants responding to signals (Table 12) compared with the baseline Adjusted Annual Average Zonal TLFs

Table 12: Three cases of participants responding to signals

From Location	BMU ID(s)	From Node(s)	From GSP Zone	To Node	To GSP Zone
Drax (case 1: **DRAX – Capacity 3,946MW**)	T_DRAXX-1 T_DRAXX-10G T_DRAXX-12G T_DRAXX-2 T_DRAXX-3 T_DRAXX-4 T_DRAXX-5 T_DRAXX-6 T_DRAXX-9G	DRAX41/ DRAX42	M	KINO40	J
Longannet (case 2: **LONG – Capacity 2.4GW**)	T_LOAN-1 T_LOAN-2 T_LOAN-3 T_LOAN-4 T_LOAND-1 T_LOAND-2	LOAN20	N	KINO40	J
Killinholme (case 4: **KILL – Capacity 462MW**)	T_KILLPG-2	KILL42	M	KINO40	J

Figure 50 presents the Adjusted Annual Average Zonal TLFs for the three cases of participants responding to signals (**Table 12**) compared with the baseline the Adjusted Annual Average Zonal TLFs. While Killinholme case is hardly distinguishable from the baseline case, Drax and Longannet cases are significantly different from the baseline case. The size of the impact that participants' relocation is related the locations and the their Metered Quantities (**Table 13**), or more precisely, their Nodal Power Flows.

Table 13: Participants' operation over 623 SSPs

	Generation Capacity	Total QM	Average QM
	MW	MWh	MWh
Killingholme	**452**	**29,424**	**47**
Longannet	**2,400**	**286,713**	**460**
Draxx	**3,946**	**822,808**	**1321**

In some cases participants responding to signals can influence the Adjusted Annual Average Zonal TLFs significantly.

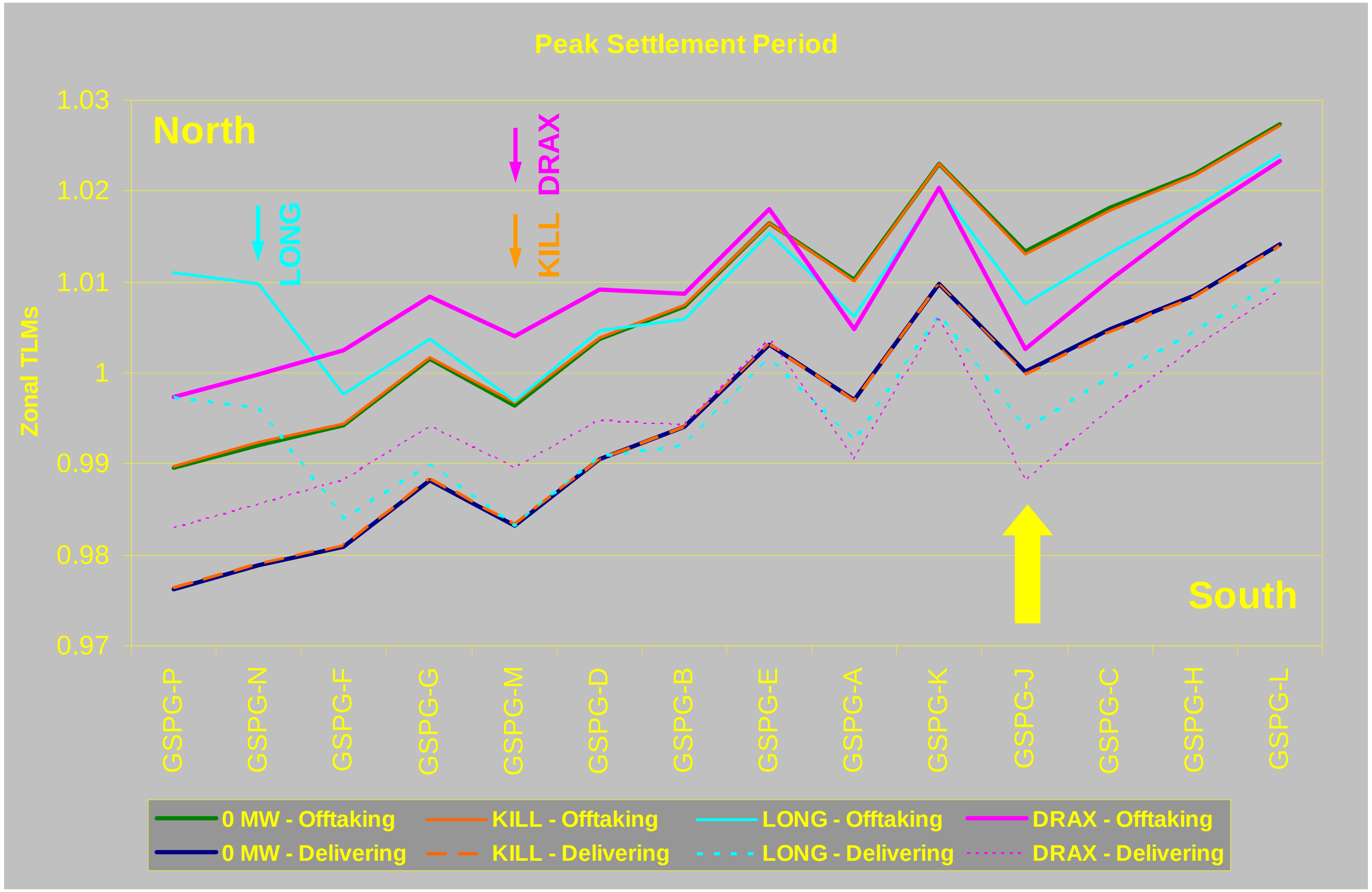


Figure 51: Delivering and Off-taking Zonal TLMs for the peak SP, for the four cases of participants responding to signals (Table 12) compared with the baseline case (0MW relocated)

Illustrative Delivery and Off-taking Zonal TLMs for peak SP for the three cases of participants responding to signals (as described above, in **Table 12**) are presented in **Figure 51**. These Zonal TLMs are compared with the baseline Delivering and Off-taking Zonal TLM (0 MW relocated) for the same SP.

5.10 Task 9: Investigate the extent of demand or generation relocation produces a reduction in overall heating losses

Task 9 considers the effect of participants responding to signals on the overall system heating losses. The cases examined are the three cases set in Task 8 and described in Section 5.9 (summarised in **Table 12** and in **Table 13**).

The heating losses considered in this task are those calculated by the model. The calculated losses differ from the Metered Volume Losses. As already indicated in Section 5.5.3, this is due to ***(i)*** the model (which initially ignored the any difference between generation and demand), ***(ii)*** fixed losses that are not treated in the model, and ***(iii)*** possible problems with the consistency and accuracy of the Metered Volumes. Metered Volumes for the cases designed for Task 8 and Task 9 did not exist (they are hypothetical). However, calculated losses are a very good indication for the actual level of heating looses as well as for any changes in these losses due to the considered scenarios.

On this small sample of cases the correlation between the significant impact of generation relocation on Adjusted Annual Average Zonal TLFs and on the overall heating losses is obvious. With regard to the baseline overall heating losses, Killinholme case hardly change the overall heating losses. Drax and Longannet cases reduce the overall heating losses significantly (**Table 14**).

Although the sample is very small, such a correlation is expected as the TLFs are directly related to the heating losses.

Table 14: Three cases of participants responding to signals

Case	Generation capacity	From node(s) (Zone)	To Node (Zone)	Losses	Change
Baseline Case	/	/	/	125,549.20 MWh	/
DRAX	3,946MW	DRAX41/ DRAX42 (GSPG-M)	KINO40 (GSPG-J)	114,971.00 MWh	-8.4%
KILL	452MW	KILL42 (GSPG-M)	KINO40 (GSPG-J)	124,512.20 MWh	-0.8%
LONG	2,400MW	LOAN20 (GSPG-N)	KINO40 (GSPG-J)	120,011.75 MWh	-4.4%

In some cases participants responding to signals can change the overall heating losses significantly.

5.11 Task 10: Examine sensitivity to breakdown/withdrawal of plant

This task looked at the cases where certain plant experienced a breakdown or it is withdrawn.

To model this, the Metered Volume of a 1500 MW capacity plant in the required location was reduced to zero. Metered Volumes of all other generators in the Settlement Period were then increased proportionally with a total increase equal to that removed.

Two plants were chosen for this task, one in the **north** and one in the **south** of the GB transmission system – presented in **Table 15**. Also the task looks at the plant breakdown/withdrawal through the four seasons. For that reasons four indicative SSP were chosen as listed in **Table 16**.

The results are presented in **Figure 52**, **Figure 53**, **Figure 54**, and **Figure 55**.

Table 15: Two plants chosen for the task

Plant name	Belong to Zone
Peterhead	GSPG-P – North Scotland
Didcot	GSPG-H – Southern

Table 16: Four indicative SSPs chosen for the task

Season	Sample Settlement Period
Winter	20060123-38
Spring	20050413-29
Summer	20050622-26
Autumn	20051123-33

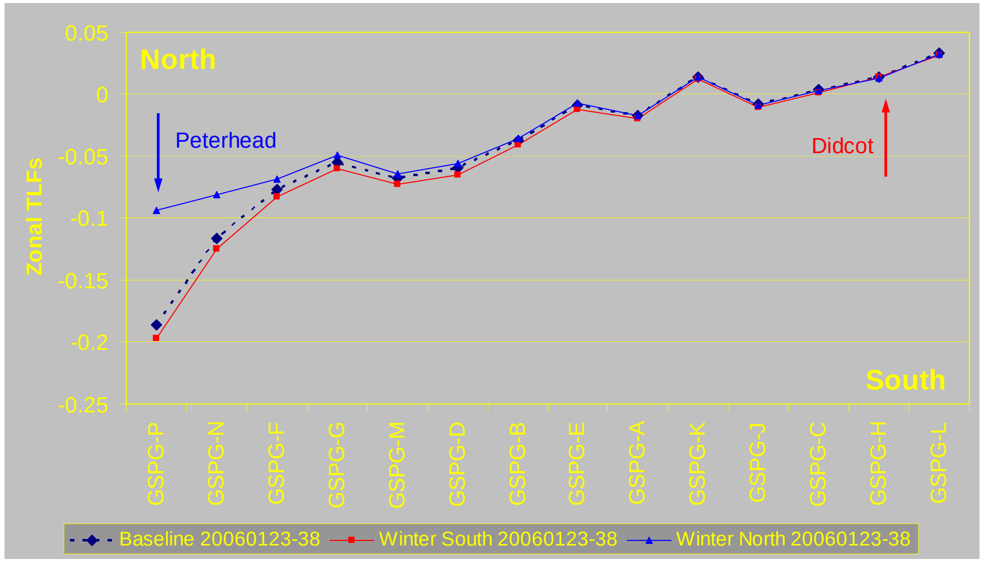


Figure 52: SSP Zonal TLFs for winter cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

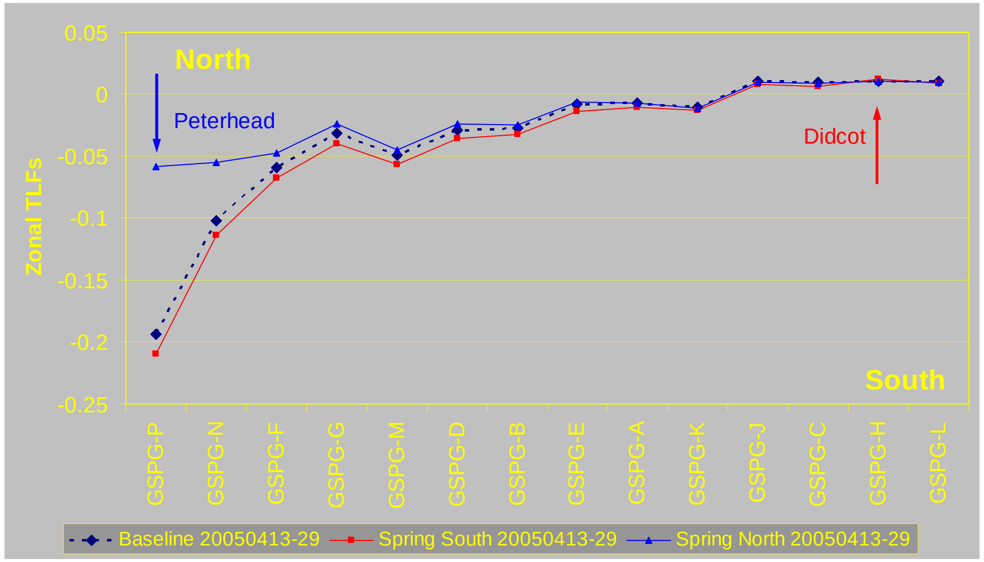


Figure 53: SSP Zonal TLFs for spring cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

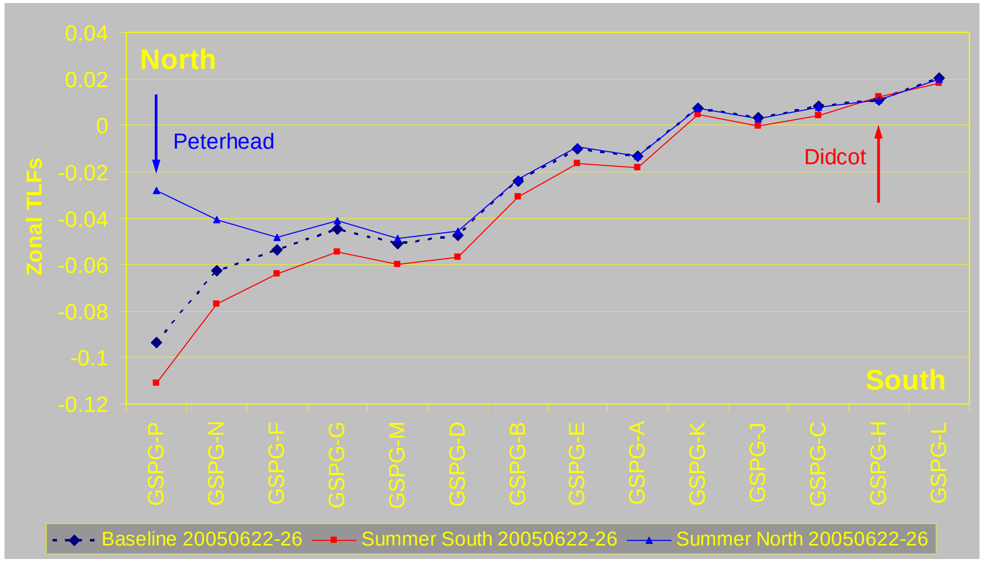


Figure 54: SSP Zonal TLFs for <u>summer</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

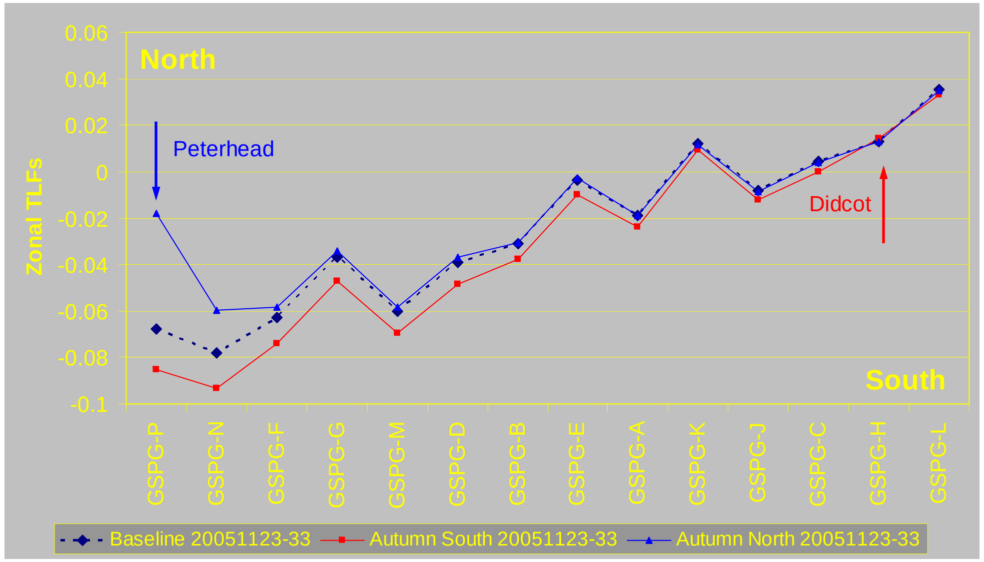


Figure 55: SSP Zonal TLFs for <u>autumn</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

Through all seasons the plant breakdown/withdrawal in the south has an effect of changing the Adjusted SSP Zonal TLFs in direction of negative values. The effect increases gradually through the zones from south to north.

Through all seasons the plant breakdown/withdrawal in the north has an effect of changing the Adjusted SSP Zonal TLFs in direction of negative values. The effect increases through the zones from south to north. However, the effect in the south is relatively modest and only increases considerably at the north.

The effect of plant breakdown/withdrawal is greatest in the north when a local plant is affected.

5.12 Task 11: Modelling of intermittent generation

To support consideration of the introduction of large volumes of intermittent generation under Task 11, the following approach was utilised:

- The output pattern (in terms of load level) of an existing wind farm (≈100MW capacity) across the sample Settlement Periods was identified;
- This output pattern was then used to generate estimated metered volumes for a 2000MW capacity wind farm across the 623 sample Settlement Periods;
- The output of this new wind farm was then introduced at various different nodes on the network as set out in **Table 17**. The output of other generators was scaled down by an amount equal to the output of the new wind farm in each sample Settlement Period. For this purpose generators were chosen via a combination of capacity, frequency of operation and random selection.

Table 17: Six cases of increased intermittent generation at different nodes

Case Location	BMU ID	NODE	Zone
Cornwall - Indian Queens	T_INDQ-1	INDQ40	GSPG-L (South Western)
Scottish Borders - Hunterston	T_HUNB-7	CRUA20	GSPG-N (South of Scotland)
Scottish Highlands – Peterhead	T_PEHE-1	PEHE40	GSPG-P (North of Scotland)
Wales – Baglan Bay	T_BAGE-1	BAGB20	GSPG-K (South Wales)
Grain	T_GRAI-1	GRAI40	GSPG-J (South Eastern)
Humberside - Killingholme	T_KILNS-1	KILL41	GSPG-M (Yorkshire Electricity)

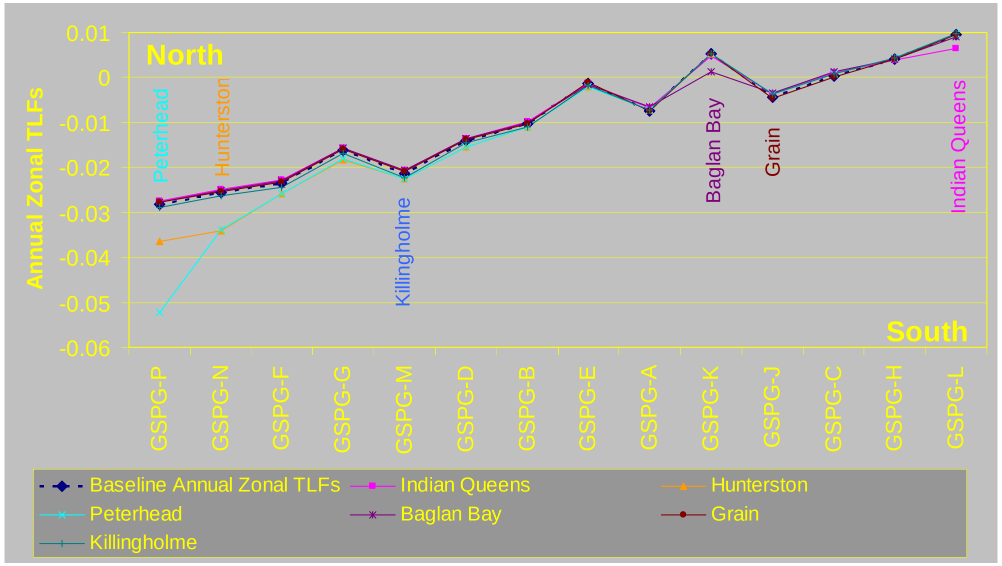


Figure 56: Adjusted Annual Average Zonal TLFs for various cases of intermittent generation locations

For each of the six location cases for the increased intermittent generation Adjusted Annual Average Zonal TLFs were calculated. The results are presented in **Figure 56** against the baseline Adjusted Annual Average Zonal TLFs.

Increased intermittent generation in the north would amplify negative values of the local TLFs. Similar effect can be observed for cases of Indian Queens and Baglan Bay. Increased intermittent generation in cases of Killingholme and Grain is too small to be obvious.

Therefore, effect of increased intermittent generation tends to be on the local TLFs.

The effect of increased intermittent generation in most cases is on the local TLFs.

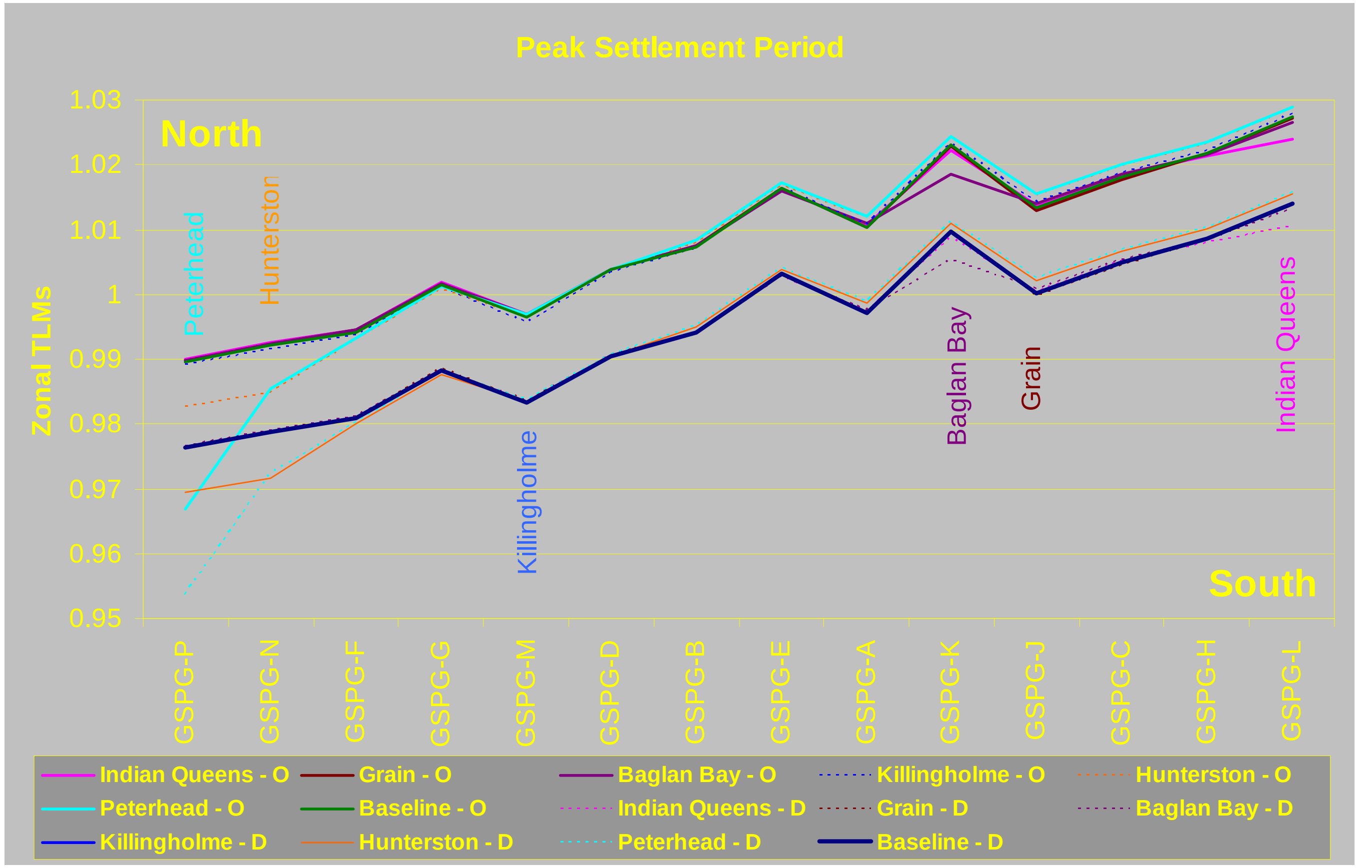


Figure 57: Delivering and Off-taking Zonal TLMs for the peak SP, for the six locations for increased intermittent generation (see Table 17) compared with baseline Zonal TLMs for the same SP (Key: O - Offtaking, D - Delivering)

Illustrative Delivering and Off-taking Zonal TLMs for peak SP for the six locations for increased intermittent generation (as described above, **Table 17**) are presented in **Figure 57**. These Zonal TLMs are compared with the baseline Delivering and Off-taking Zonal TLMs for the same SP.

5.13 Task 12: Separate consideration of 132 kV

This task was designed to demonstrate the likely influence of Scottish 132 kV network on Adjusted Annual Average Zonal TLFs should this network be withdrawn for GB transmission system losses allocation considerations. For the purpose of this task resistance of Scottish 132 kV network branches were set to zero, while leaving reactance of these branches intact. In that way, due to the use of DC load flow, the influence of these 132 kV network branches on the overall power flows was preserved, but their direct contribution to losses, and thus to TLFs was annulled.

The reduction in overall calculated losses (over all 623 SSP) was 5.9%.

The effect of excluding the Scottish 132 network branches from calculating the losses on Adjusted Annual Average Zonal TLFs, is relatively small and predominantly of local character (**Figure 58** and **Table 18**)

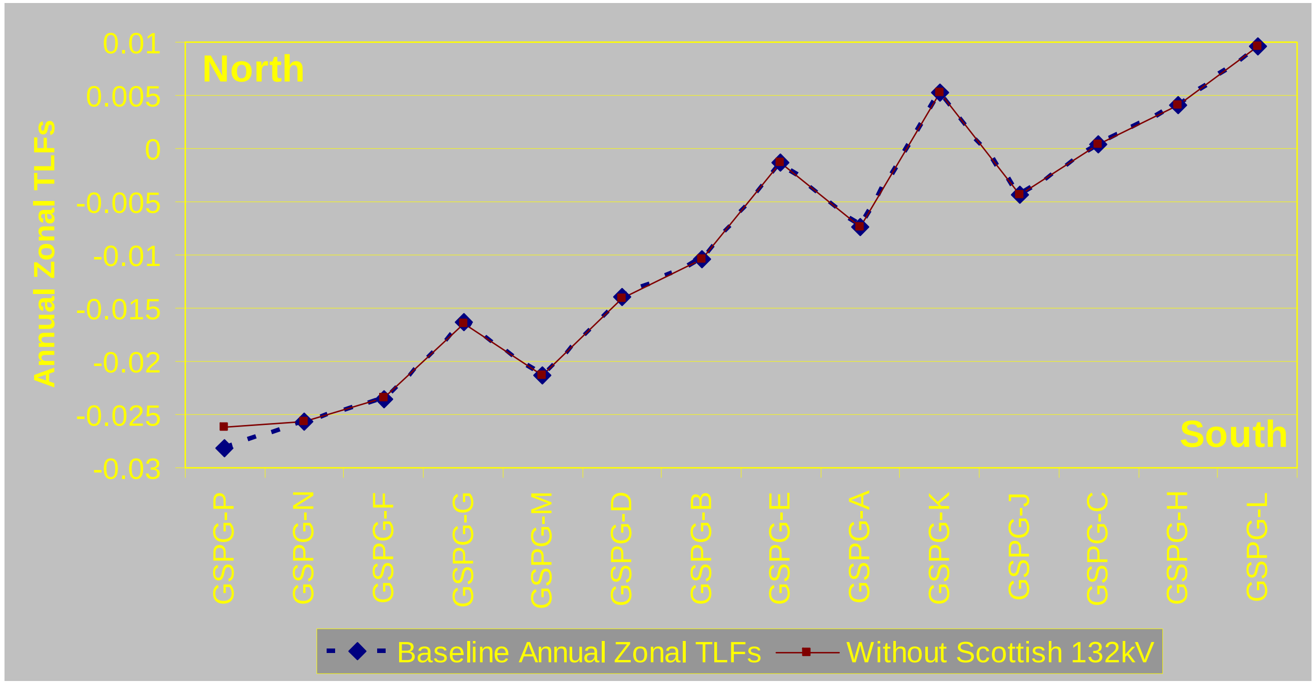


Figure 58: Adjusted Annual Average Zonal TLFs in case 132 kV Scottish network is not accounted for the losses compared to the baseline Adjusted Annual Average Zonal TLFs

Table 18: Adjusted Annual Average Zonal TLFs for Baseline case and for the case without the 132 kV Scottish network

	AAA Zonal TLFs	
Zone	Baseline Annual Zonal TLFs	Without Scottish 132kV Network
GSPG-P	-0.02818	-0.02622
GSPG-N	-0.02561	-0.02564
GSPG-F	-0.02355	-0.02336
GSPG-G	-0.01625	-0.01645
GSPG-M	-0.02127	-0.02125
GSPG-D	-0.01399	-0.01406
GSPG-B	-0.01038	-0.01037
GSPG-E	-0.00133	-0.00135
GSPG-A	-0.00742	-0.00741
GSPG-K	0.0053	0.00529
GSPG-J	-0.0043	-0.00429
GSPG-C	0.00039	0.00039
GSPG-H	0.00414	0.00414
GSPG-L	0.00963	0.00963

The effect of withdrawing Scottish 132 kV network on Annual Average Zonal TLFs is relatively small and of local character.

Illustrative Delivering and Offtaking Zonal TLMs for peak and trough SPs were calculated for the case without influence of 132kV Scottish network on losses and thet are presented in **Figure 59** and **Figure 60**. These Zonal TLMs are compared with Delivering and Offtaking Zonal TLMs for the same Sp for the case including the influence of 132kV Scottish network on losses. This comparison is complemented with the TLMs as that are currently calculated (i.e. with TLF = 0).

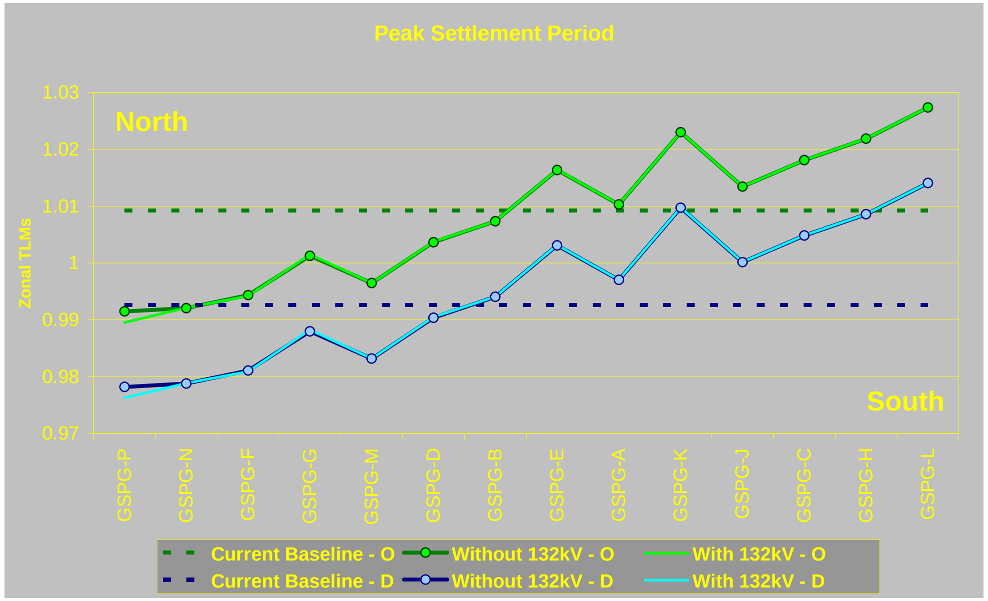


Figure 59: Delivering and Offtaking Zonal TLM for <u>peak</u> SP for case of withdrawing the influence of 132kV Scottish network on losses, compared to case with the 132kV Scottish network (TLMs as currently calculated, i.e. with TLF = 0) are also included

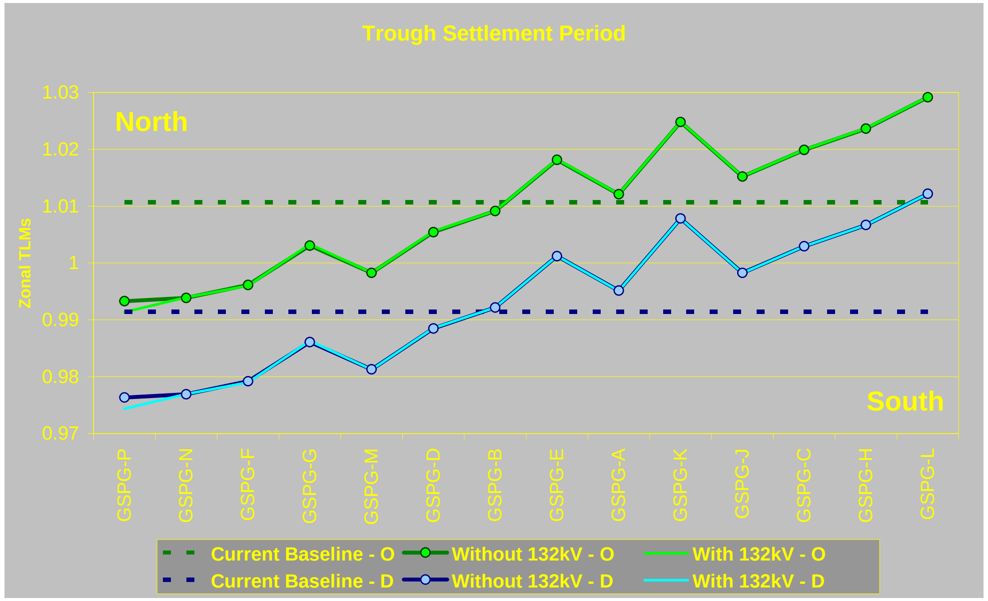


Figure 60: Delivering and Offtaking Zonal TLM for <u>trough</u> SP for case of withdrawing the influence of 132kV Scottish network on losses, compared to case with the 132kV Scottish network (TLMs as currently calculated, i.e. with TLF = 0) are also included

6 AN ISSUE WITH THE METHOD FOR CALCULATING SSP ZONAL TLFS

For each Sample Settlement Period (SSP) the Zonal TLF (ZTLFj) for each Zone are determined according to the following formula: ZTLFj = ΣN (NTLFj * ANQMj) / ΣN ANQMj, where for that Settlement Period, and ***(i)*** for each Node in that Zone, NTLFj is the value of Nodal TLF; ***(ii)*** ANQMj is the **absolute** value of the nodal power flow (value based on delivery and off-take metered volumes); and ***(iii)*** where ΣN is summation by Node in a Zone. For guidance on the zones see Section 5.1. The initial observation was that such a ZTLFj does not recover the same losses as the NTLFj recover in that same zone, indicating some additional re-allocation of losses.

The convention is that delivery metered volumes have positive sign and that off-take metered volumes have negative sign and that is also preserved with the Nodal Power Flows. In numerically well conditioned cases the Zonal TLF (ZTLFj) for each Zone could be determined by ZTLFj = ΣN (NTLFj * NQMj) / ΣN NQMj, where NQMj is the value (with its sign) of the Nodal Power Flow. Such a ZTLFj does recover exactly the same losses as the NTLFj recover in that same zone. However, if the sum ΣN NQMj = 0, ZTLFj would not be possible to calculate, and in case the sum ΣN NQMj ≈ 0, the re-allocation of losses within the zone would be extremely out of proportion. Although such cases are highly improbable this approach was not acceptable for a live application.

Some further problems were subsequently observed with both above approaches to calculating Zonal TLFs. A particular Zonal TLFs for a particular SSP is meant to be a weighted average of Nodal TLFs in that Zone and for that SSP, what inevitably brings about some degree of re-allocation of losses. However, both approaches and particularly the second one above (one using NQMj) can reverse the sign of allocated losses (the difference is between being charged for causing losses and rewarded for reducing losses) to an excessive extent – in **Figure 63** zone β has two generators (nodes 67 and 68) and Nodal TLFs would “penalise” both of them while Zonal TLFs wold “reward” both of them at expense of the demand nodes.

If in each zone nodes with positive net Nodal Power Flows (“delivery” nodes) and nodes with negative net Nodal Power Flows (“off-take” nodes) are treated separately, using ZTLFj = ΣN (NTLFj * NQMj) / ΣN NQMj formula (i.e. $^{+}$ZTLFj = ΣN (NTLFj * $^{+}$NQMj) / ΣN $^{+}$NQMj and $^{-}$ZTLFj = ΣN (NTLFj * $^{-}$NQMj) / ΣN $^{-}$NQMj respectively), and thus getting two separate Zonal TLFs per Zone for a SSP, the problems described above would be avoided. This consideration of “Delivery” Zonal TLF and “Off-take” Zonal TLF per each Zone and for each SSP, is related to single system of Zones, equally defined for both “Delivery” and “Off-take” nodes.

Approach and some relevant characteristics

A) ZTLFj = ΣN (NTLFj * ANQMj) / ΣN ANQMj	B) ZTLFj = ΣN (NTLFj * NQMj) / ΣN NQMj	C) $^{-}$ZTLFj = ΣN (NTLFj * $^{-}$NQMj) / ΣN $^{-}$NQMj $^{+}$ZTLFj = ΣN (NTLFj * $^{+}$NQMj) / ΣN $^{+}$NQMj
▪ It does not provide recovery of losses equal to recovery of losses by Nodal TLFs ▪ The main application rationale appears to be avoiding possible numerical problems with approach (B) ▪ It demonstrates an inconsistency in re-allocation of losses	▪ In numerically well conditioned cases the recovery of losses is exactly equal to recovery of losses by Nodal TLFs ▪ In rare cases does not have a solution ▪ In rare cases the re-allocation of losses within the zone would be out of proportion to the extreme ▪ It demonstrates possibility of significant sign swaps in re-allocation of losses	▪ Recovery of losses is exactly equal to recovery of losses by Nodal TLFs ▪ Does not have the stated problems of approaches (A) and (B) ▪ It avoids re-allocation of losses between “delivery” and “off-take” nodes (with regard to the nodal power flows), inherent to approaches (A) and (B) ▪ It doubles the number of Zonal TLFs

Concerns with the calculation method for Zonal TLFs for a SP led to further examination of the alternative method C.

Comparison of loss recoveries by Nodal TLFs, by Zonal TLFs (approach A), and by Zonal TLFs (approach B)

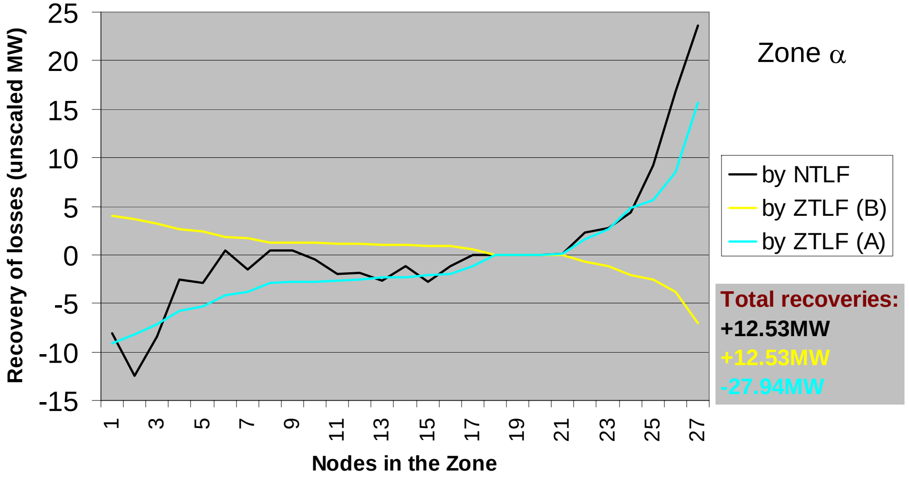


Figure 61: Comparison of loss recoveries in a Zone α (methods A & B)

Comparison of loss recoveries by Nodal TLFs, by Zonal TLFs (approach A), and by Zonal TLFs (approach C – one for "delivery" and one for "off-take")

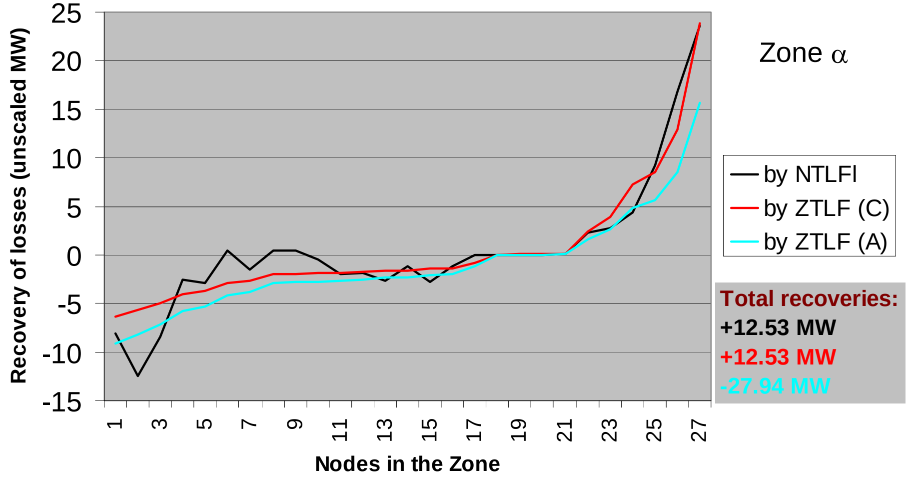


Figure 62: Comparison of loss recoveries in a Zone α (methods A & C)

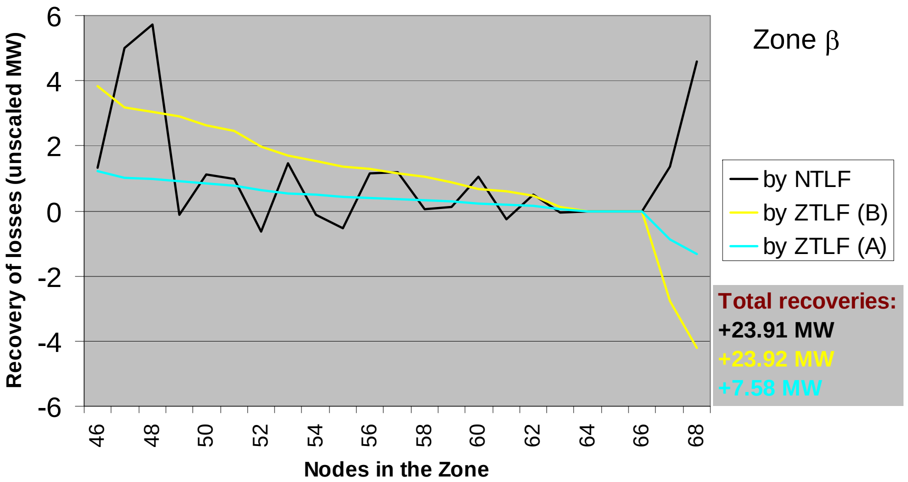


Figure 63: Comparison of loss recoveries in a Zone β (methods A & B)

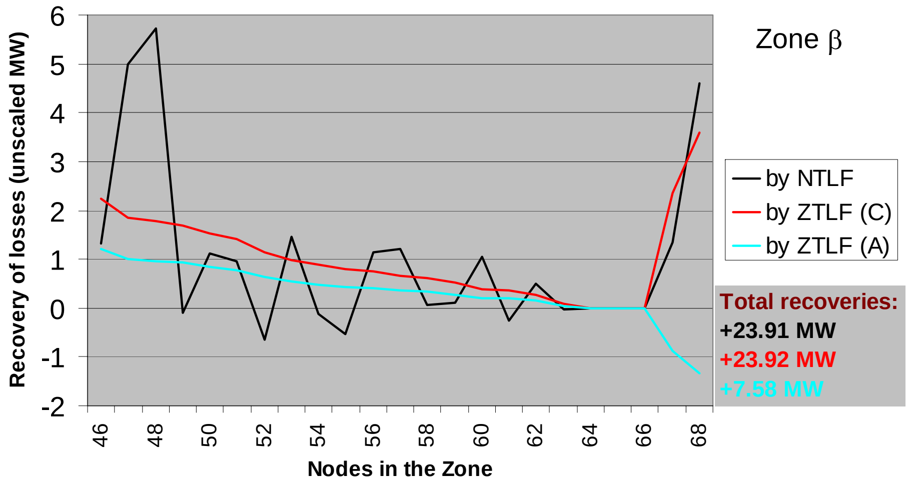


Figure 64: Comparison of loss recoveries in a Zone β (methods A & C)

6.1 Task 1b: Calculating baseline TLFs with the alternative method

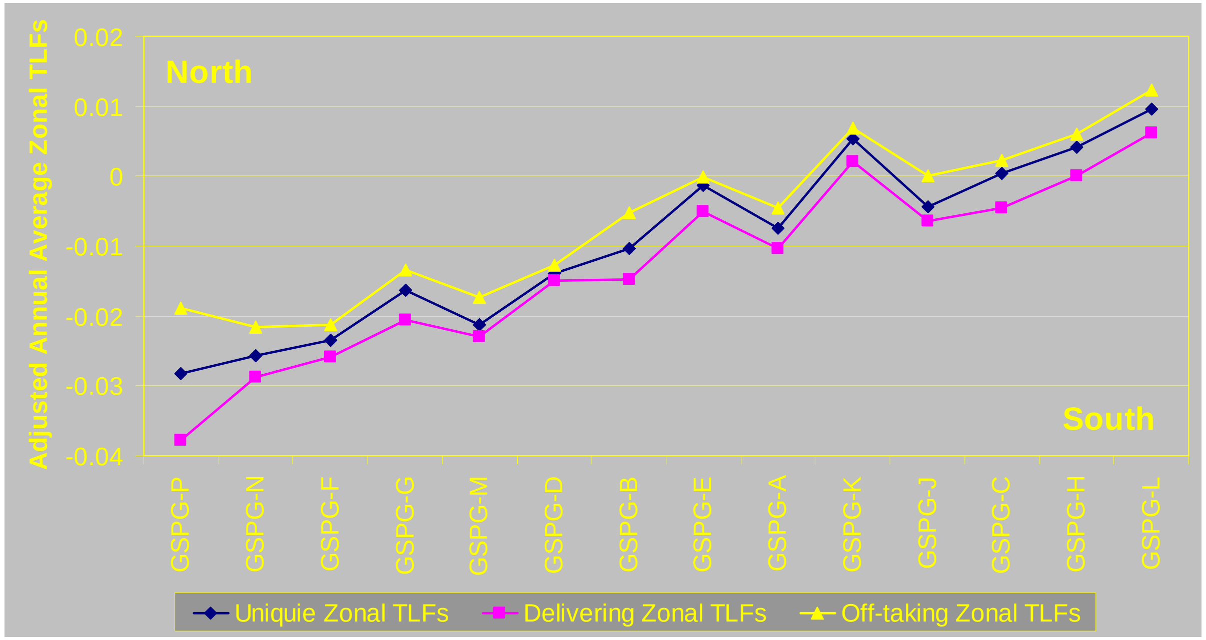


Figure 65: Alternative Baseline Adjusted Annual Average Delivering Zonal TLFs and Adjusted Annual Average Offtaking Zonal TLFs compared to Current Baseline Adjusted Annual Average Zonal TLFs

Table 19: Alternative Baseline Adjusted Annual Average Delivering and Offtaking Zonal TLFs

Zone	AAA Zonal TLFs		Zone	AAA Zonal TLFs	
	Delivering	Offtaking		Delivering	Offtaking
GSPG-P	-0.03784	-0.01888	GSPG-E	-0.005	-0.00018
GSPG-N	-0.02874	-0.02166	GSPG-A	-0.01037	-0.00458
GSPG-F	-0.02592	-0.02122	GSPG-K	0.00213	0.00693
GSPG-G	-0.02053	-0.0134	GSPG-J	-0.00648	0.00006
GSPG-M	-0.02288	-0.01739	GSPG-C	-0.00453	0.00221
GSPG-D	-0.0149	-0.01274	GSPG-H	0.00013	0.00595
GSPG-B	-0.0148	-0.00516	GSPG-L	0.00621	0.01232

As an additional requirement it was requested that the Alternative Baseline Adjusted Annual Average Zonal TLFs are calculated using the method C as described above in Section 6. This alternative method calculates for each SSP and each zone Delivering Zonal TLF ($^{+}$ZTLFj in Section 6) and Offtaking Zonal TLF ($^{-}$ZTLFj in Section 6). Therefore, this is an alternative volume-weighted averaging. Subsequent time-weighted averaging is the same as before, except that SSP Delivering and Offtaking Zonal TLFs are treated separately.

Figure 65 presents the Alternative Baseline Adjusted Annual Average Delivering and Offtaking Zonal TLFs compared to Current Baseline Adjusted Annual Average Zonal TLFs. **Table 19** presents the Alternative Baseline Adjusted Annual Average Delivering Zonal TLFs and Adjusted Annual Average Off-taking Zonal TLFs in tabular format.

Table 20 presents that the Alternative Baseline Adjusted Annual Average Delivering and Offtaking Zonal TLFs return recovered losses much closer to the calculated heating losses than current Adjusted Annual Average Zonal TLFs.

Table 20: Comparison of the recovered losses when using current AAA Zonal TLFs and when using Alternative AAA Delivering and Offtaking Zonal TLFs

Values across 623 SSPs	
Total calculated heating losses	125,549.2 MWh
Recovered losses	
Adjusted Annual Average Zonal TLFs applied on Net Nodal Power Flows	41,268 MWh
Alternative Adjusted Annual Average Delivering and Off-taking Zonal TLFs applied on corresponding Net Nodal Power Flows	108,328 MWh