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Report

MP229 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 P229 Modification Group in the assessment procedure of the BSC (Balancing and Settlement Code) Modification Proposal P229 ('Introduction of a seasonal Zonal Transmission Losses scheme').

This section presents the key summary elements of the Modification Proposal P229 and presents the MP229 Load Flow Modelling Service objectives.

2.1 Modification Proposal P229 – key summary elements

MP P229 was raised on 28th November 2008 by RWE Npower ('the Proposer').

MP P229 aims to allocate transmission loss costs more appropriately across Generators and demand customers on the GB transmission system. The solution proposed by MP229 is based closely on Proposed Modification P82, Proposed Modification P198 and Proposed Modification P203. The methodology for calculating non-zero TLFs (Transmission Loss Factors) broadly involves the following:

- An electrical model of the Transmission System (a 'Load Flow Model') would be built, containing 'Nodes' to represent points where transmission circuits meet, or energy flows on or off the Transmission System. Each Node on the Transmission System would be identified by the Transmission Company, and would be allocated to a specific Zone on the transmission network on the basis of a 'Network Mapping Statement' maintained by BSCCo. The TLF Zones would be set by the Panel, based on the geographic areas covered by GSP Groups. Since there are currently 14 GSP Groups, there would therefore be 14 TLF Zones.
- TLFs would be calculated on an ex-ante basis (i.e. calculated before the relevant year) for each BSC Year, using Metered Volumes and Network Data for Sample Settlement Periods from a preceding 12 month period (the 'Reference Year'). The required Metered Volumes and Network Data would be provided by the Central Data Collection Agent (CDCA) and the Transmission Company respectively.
- Prior to the start of each BSC Year (1 April – 31 March), the Load Flow Model would be run by a Transmission Loss Factor Agent ('the TLFA') to calculate how an incremental increase in power at each individual Node would affect the total variable losses from the Transmission System. 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 incremental increase in generation (or reduction in demand) had the effect of decreasing variable losses. Negative TLF values would be produced for Nodes where an incremental increase in generation (or reduction in demand) had the effect of increasing variable losses[1].
- The TLFA would average the raw Nodal TLFs across all the Nodes in each TLF Zone by 'volume-weighted' averaging, to give 14 Zonal TLF values for each Sample Settlement Period (one per TLF Zone). The TLFA would then convert these Zonal TLF values to Seasonal Zonal TLFs by 'time-weighted' averaging, calculating a set of four Seasonal Zonal TLFs for each TLF Zone – one for each BSC Season, as defined in Section K of the Code.
- The TLFA would adjust the Seasonal Zonal TLFs by a scaling factor of 0.5 so the volume of energy allocated via the TLFs is comparable to the volume of variable losses calculated by the Load Flow Model. The Adjusted Seasonal Zonal TLFs would be made publicly available by BSCCo no less than three months prior to their use in the TLM Settlement calculation for the applicable BSC Season.
- Each BM Unit would be allocated to a specific TLF Zone by BSCCo on the basis of the Network Mapping Statement, with any question or dispute over zonal allocation to be resolved by the Panel. The TLFA would determine the TLF value to be applied to each BM Unit in the TLM Settlement calculation for the applicable BSC Season, which would be the Adjusted Seasonal Zonal TLF value for the relevant Zone. All BM Units within a Zone would therefore receive the

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

same single TLF value for every Settlement Period in the BSC Season. A positive TLF would increase the TLM value used to scale a BM Unit's Metered Volume (a benefit to generators and disadvantage to Suppliers), and a negative TLF would decrease the TLM value (a benefit to Suppliers and disadvantage to generators).

- The BM Unit-Specific TLFs calculated by the TLFA would be registered in BSC Systems by the Central Registration Agent (CRA), and would be used by the Balancing Mechanism Reporting Agent (BMRA) and the Settlement Administration Agent (SAA) within the Balancing Mechanism Reporting Service (BMRS) and Settlement calculations respectively.
- The remaining 'fixed' element of transmission losses would continue to be allocated to Parties on a non-locational basis through the TLMO, and the overall 45:55 allocation of total transmission losses to generation and demand would be retained.
- There would be no phased implementation or 'hedging' of exposure to the new zonal TLFs, which would therefore take full effect from the first Settlement Period on the Implementation Date.
- The applicable onshore zones would be the geographical area defined by a GSP Group. For offshore nodes connected to the GB transmission system (including both DC and AC offshore networks and offshore networks connected to distribution systems) the relevant onshore GSP Group in which the network is connected would be used as the basis for the applicable zone subject to Panel determination using specific criteria.

2.2 MP229 Load Flow Modelling Service objectives

Specifically, PTI has been tasked to:

- perform calculations of TLFs for a specified number of Sample Settlement Periods (SSPs) for Modification Proposal P229;
- 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 (MP229) arising from the exercise.

2.3 Introductory notes

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 MP229 Load Flow Modelling results (i.e. TLFs) Siemens PTI submitted to ELEXON.

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 P229. Section 6 describes a methodological issue, noted during the project work, with the intention to draw the P229 Modification Group's attention to this issue; it also presents additional results obtained by using alternative methods to calculate Zonal TLFs for each SSP. The report does not have conclusions as they will arise from the P229 Modification Group assessment procedure.

3 INPUT DATA FOR THE MODELLING EXERCISE

3.1 Settlement Periods data

Table 1: List of Settlement Periods for which delivering and off-taking metered volumes data were provided by ELEXON

<table>
<tr><th>Tasks for which these SSPs were used</th><th>Sample Settlement Periods (SSPs) used</th></tr>
<tr><td>There were 630 Sample Settlement Periods (SSPs) from period December 2007 to November 2008 split into seasonal sets (seasons as defined in the BSC) as for the baseline input data sets (Data Set 1). These SSPs and their Metered Volumes were also used in different arrangements (annual, seasonal and monthly) and in association with different tasks. These tasks were Task 1 (baseline TLFs), Task 2 (temporal variability of TLFs), Task 3 (Nodal vs. Zonal average TLFs), and Task 4 (TLFs sensitivity to interconnections flows).</td><td>630 SSP (Dec. 07 to Nov. 08) ➔ Winter 156 SSps
Spring 160 SSps
Summer 158 SSPs
Autumn 156 SSPs ➔ Dec 07 55 SSPs
Jan 08 50 SSPs
Feb 08 51 SSPs
Mar 08 55 SSPs
Apr 08 49 SSPs
May 08 56 SSPs
Jun 08 51 SSPs
Jul 08 53 SSPs
Aug 08 54 SSPs
Sep 08 51 SSPs
Oct 08 51 SSPs
Nov 08 54 SSPs</td></tr>
<tr><td>There were 8 particularly designed sets of Seasonal SSPs Metered Volumes (related to 2 scenarios) for Task 5 and Task 6 that looked at sensitivity of Seasonal TLFs to participants responding to signals</td><td>Winter 156 SSps
Spring 160 SSps
Summer 158 SSPs
Autumn 156 SSPs</td></tr>
<tr><td>There were 8 particularly selected and designed single SSP Metered Volumes used in Task 7 to examine sensitivity to breakdown/withdrawal of plant</td><td>Spring South 20080303,34 1 SSP; Summer South 20080604,24 1 SSP
Spring North 20080303,34 1 SSP; Summer North 20080604,24 1 SSP
Autumn South 20081126,38 1 SSP; Winter South 20071219,33 1 SSP
Autumn North 20081126,38 1 SSP; Winter North 20071219,33 1 SSP</td></tr>
<tr><td>There were 8 particularly designed sets of Seasonal SSPs Metered Volumes (related to 2 scenarios) for Task 8 that modelled the effects of intermittent generation</td><td rowspan="3">Winter 156 SSps
Spring 160 SSps
Summer 158 SSPs
Autumn 156 SSPs</td></tr>
<tr><td>There were 4 particularly adjusted/designed sets of Seasonal SSPs Metered Volumes for Task 9 that was examining the impact of including the offshore transmission nodes</td></tr>
<tr><td>There were 4 particularly designed sets of Seasonal SSPs Metered Volumes for Task 10 that was designed to examine the impact of large offshore delivery, new interconnections and new DC offshore transmission</td></tr>
</table>

Delivering and off-taking 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 10 specified Tasks (see **Table 1**).

The Tasks, specified by the Terms of Reference (described in more detail in Section 5.2 to Section 5.11), were designed with the aim to demonstrate the key representative features of Modification Proposal P229, as required by the P229 Modification Group for the assessment procedure. For this purpose each of the Tasks combines selected Sample Settlement Periods data with particular network data.

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

3.2 Network data

Table 2: List of network data used in the MP229 Load Flow Modelling

Network Data	
Network	**Tasks the network data were used for**
Intact (winter) network	Task 1, Task 2, Task 3, Task 4, Task 5 , Task 6, Task 7, and Task 8
Extended Intact network to include current offshore 132kV and above nodes as well as such nodes expected in near future	Task 9
Extended Intact network to include envisaged interconnections and DC offshore transmission	Task 10

In order to enable load flow calculations and calculations of marginal TLFs, the delivering and off-taking metered volumes data for specific Settlement Periods (**Table 1**) were combined with appropriate detailed transmission network data. The list of different transmission networks used in the MP229 Load Flow Modelling is given in **Table 2** together with the indication in which tasks these networks were used.

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

The intact transmission network was assumed to be most complete (i.e. to have the largest and most complete set of network elements in operation).

The transmission network models for Task 9 and Task 10 were derived from the intact transmission network model in consultation with the P229 Modification Group

Actual network data from the past were used to produce the intact transmission network as well as the basis for modified transmission networks for the modelling calculations.

4 MODELLING APPROACH

4.1 Method

Modification Proposal P229 proposes calculation of zonal half hourly (½ h) TLMs based on zonal ½ h TLFs, which are based on seasonal 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) Seasonal Average Zonal TLFs were calculated using the principles of 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. Seasonal average Zonal TLFs were calculated using a time weighted averaging of Zonal ½ h TLFs. The alternative methods to calculate ½ h Zonal TLFs (i.e. for zonal averaging of Nodal TLFs for a particular ½ h) are described in Section 6

For all 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 MP229 Modelling Project some variants of the LFM Operational Software were utilised 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

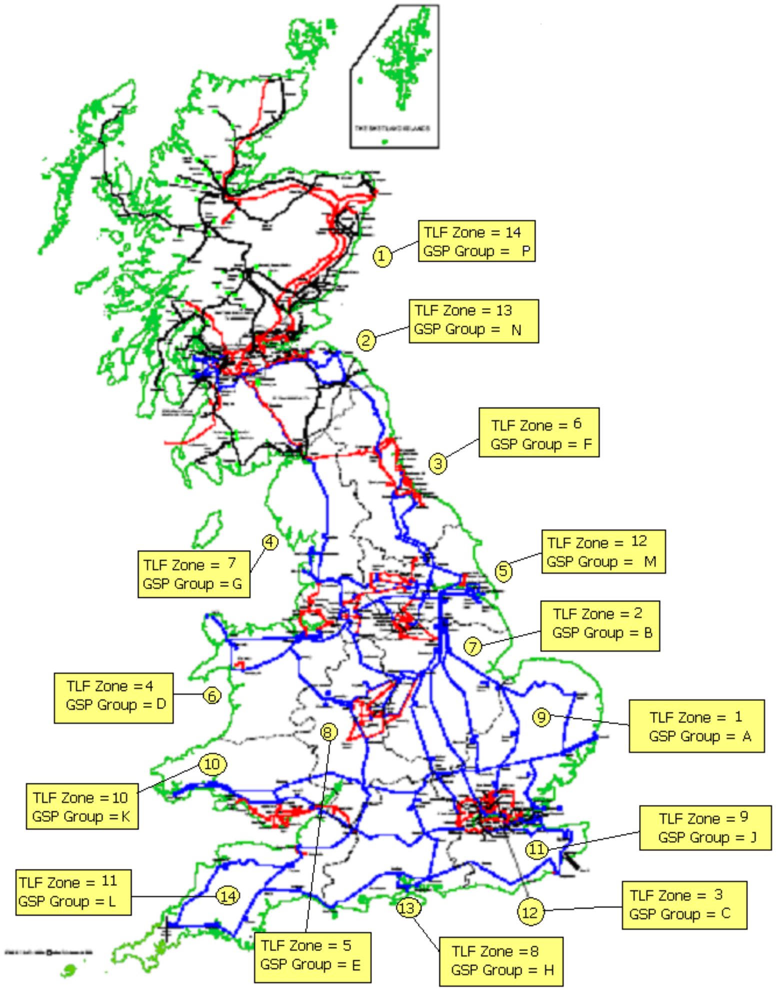

Figure 1: Guidance for the Zones as applied in the Project

This section presents the MP229 Load Flow Modelling Project results. The project work was divided into 10 Tasks and results for each Task are given in a separate section. The first section describes the Zones as implemented in this project.

5.1 Zones as applied in the MP229 Modelling Project

MP229 suggests that "the applicable onshore zones would be the geographical area defined by a GSP Group. For offshore nodes connected to the GB transmission system"…"the relevant onshore GSP Group in which the network is connected would be used as the basis for the applicable zone subject to Panel determination using specific criteria." This indicated unique zones for both generation and demand.

The Network Mapping Statement, input data provided by ELEXON and National Grid, 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 a 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

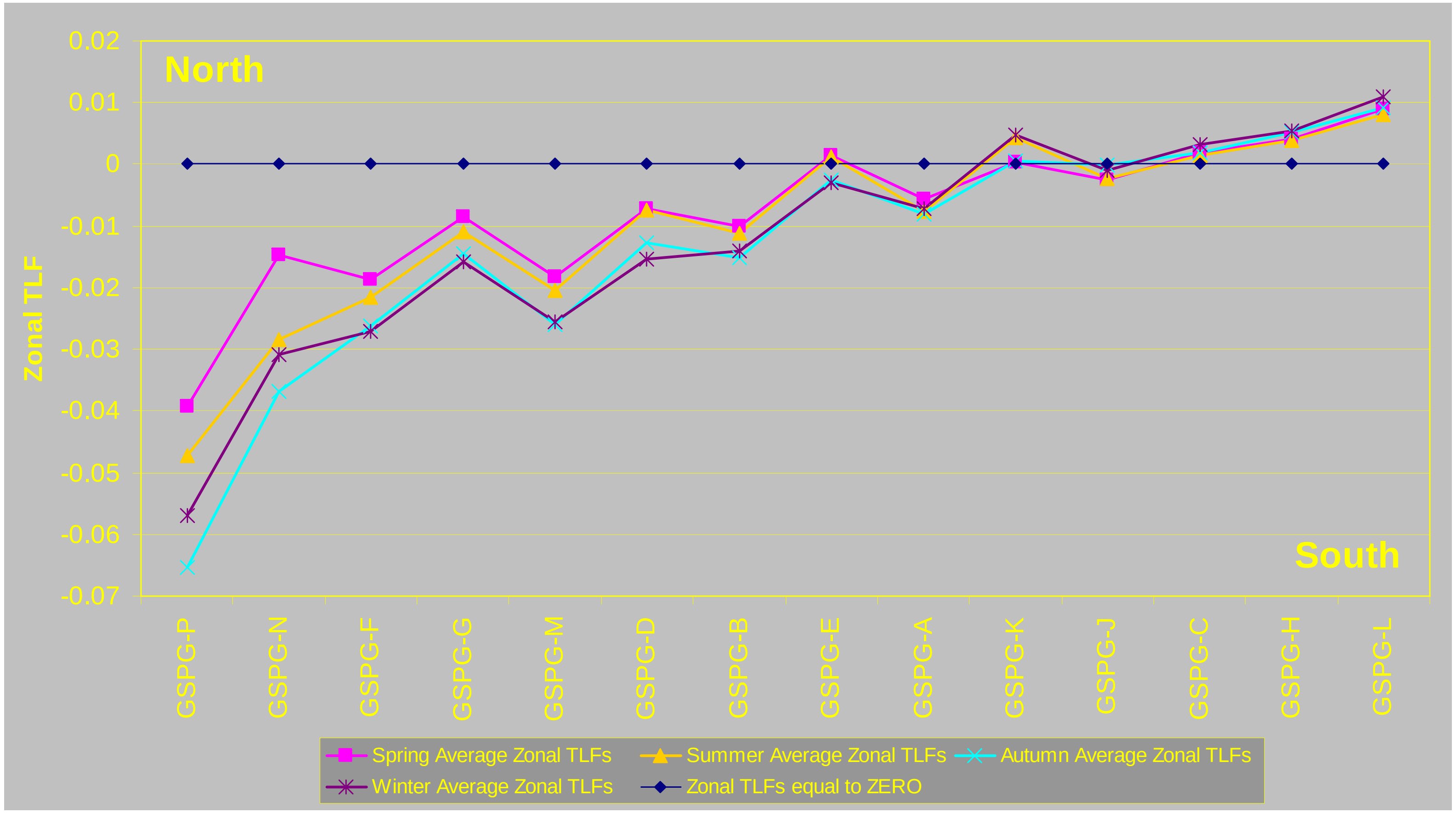

Figure 2: Baseline Adjusted Seasonal Average Zonal TLFs vs. current TLFs that are equal to zero

Introduction of P229 would result in geographically variable Zonal TLFs and thus in geographically variable TLMs.

Table 4: Baseline Adjusted Seasonal Average Zonal TLFs

Zone	Spring Average Zonal TLFs	Summer Average Zonal TLFs	Autumn Average Zonal TLFs	Winter Average Zonal TLFs
GSPG-P	-0.03919	-0.0472	-0.06535	-0.05685
GSPG-N	-0.01471	-0.02838	-0.03687	-0.03093
GSPG-F	-0.01878	-0.02148	-0.02612	-0.02718
GSPG-G	-0.00863	-0.01085	-0.01456	-0.01592
GSPG-M	-0.01835	-0.02047	-0.02597	-0.02558
GSPG-D	-0.00719	-0.00736	-0.01267	-0.01546
GSPG-B	-0.01012	-0.0112	-0.01513	-0.01411
GSPG-E	0.00152	0.00117	-0.00262	-0.0031
GSPG-A	-0.0057	-0.00765	-0.00803	-0.00724
GSPG-K	0.00031	0.0043	0.00063	0.00472
GSPG-J	-0.00251	-0.00223	-0.00008	-0.00102
GSPG-C	0.00176	0.00133	0.00187	0.00318
GSPG-H	0.00413	0.00387	0.00524	0.00533
GSPG-L	0.00898	0.00806	0.00917	0.01091

Currently the BSC calculates TLMs with TLFs set to zero. MP229 proposes Adjusted Seasonal Average Zonal TLFs that will vary geographically, reflecting the contribution to variable heating system losses by the generation and demand.

For calculation of the baseline Adjusted Seasonal Average Zonal TLFs ELEXON selected 630 Sample Settlement Period (SSPs) from the period December 2007 to November 2008 inclusively. The use of 630 SSPs is similar in size and structure to what could be the sample for live calculations of the Adjusted Seasonal Average Zonal TLFs for use in the settlement procedure.

Therefore, the Metered Volumes used in calculations 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 Seasonal Average Zonal TLFs as put against TLFs currently used in the settlement procedure.

Table 4 presents numerical values of the calculated baseline Adjusted Seasonal Average Zonal TLFs.

The meaning of specially arranged signs of the Adjusted Seasonal Average Zonal TLFs in **Figure 2** and **Table 4** should be noted: a negative Adjusted Seasonal 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.

The baseline Adjusted Seasonal 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 all SSPs for that season using a time weighted averaging. **Figure 3** to **Figure 6** indicate variability of SSP Zonal TLFs that make the baseline Adjusted Seasonal Average Zonal TLFs. These illustrations are based on 4 SSPs per each season selected by ELEXON.

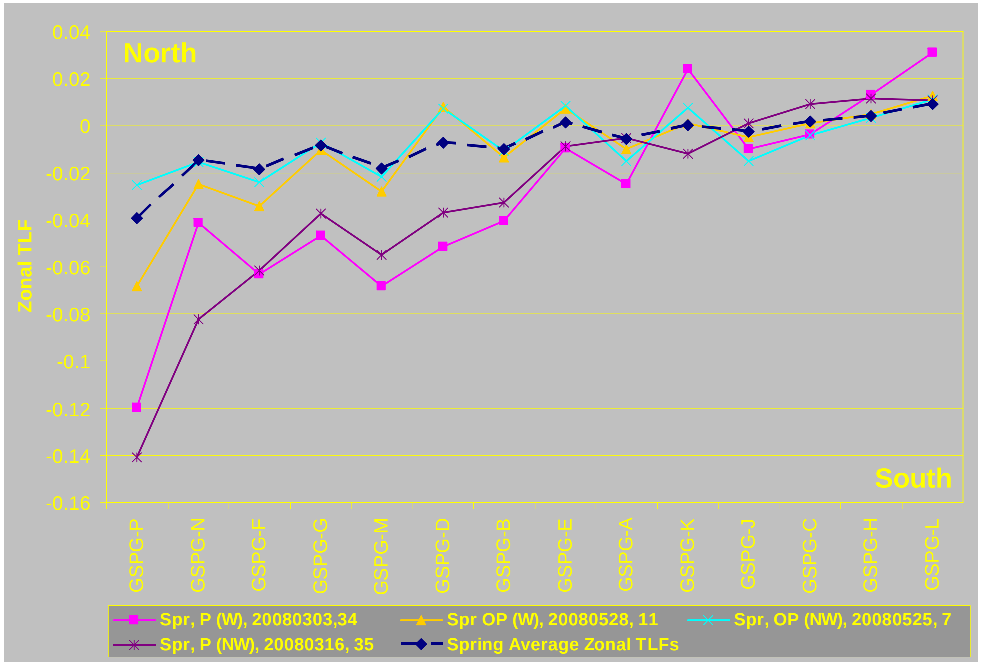

Figure 3: Illustrative variability of SSP Zonal TLFs on the basis of which the baseline Adjusted Seasonal Average Zonal TLFs were produced – Spring (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working)

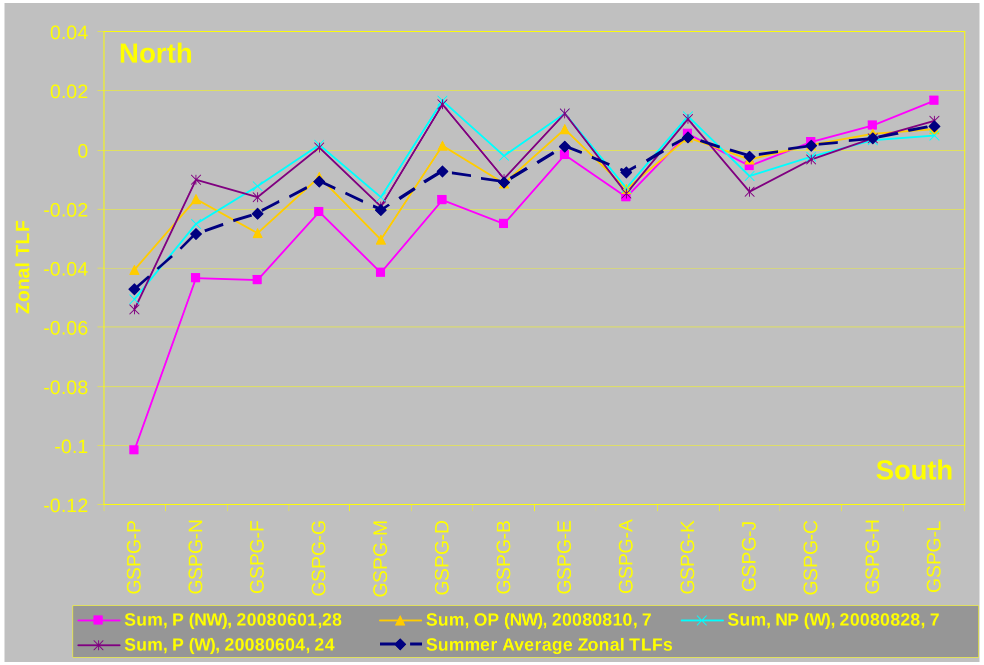

Figure 4: Illustrative variability of SSP Zonal TLFs on the basis of which the baseline Adjusted Seasonal Average Zonal TLFs were produced – Summer (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working)

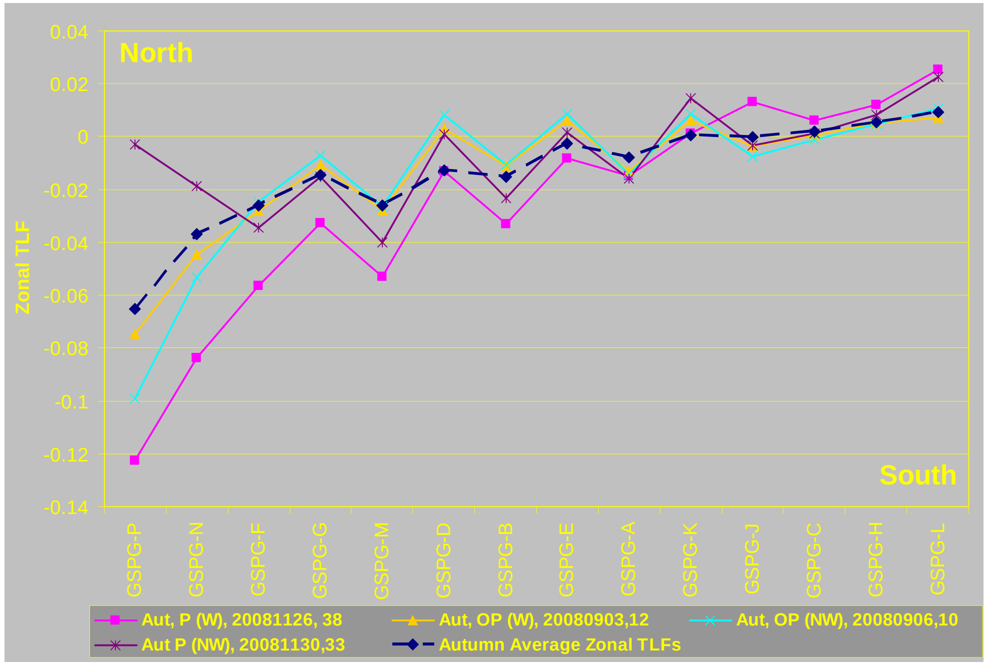

Figure 5: Illustrative variability of SSP Zonal TLFs on the basis of which the baseline Adjusted Seasonal Average Zonal TLFs were produced – Autumn (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working)

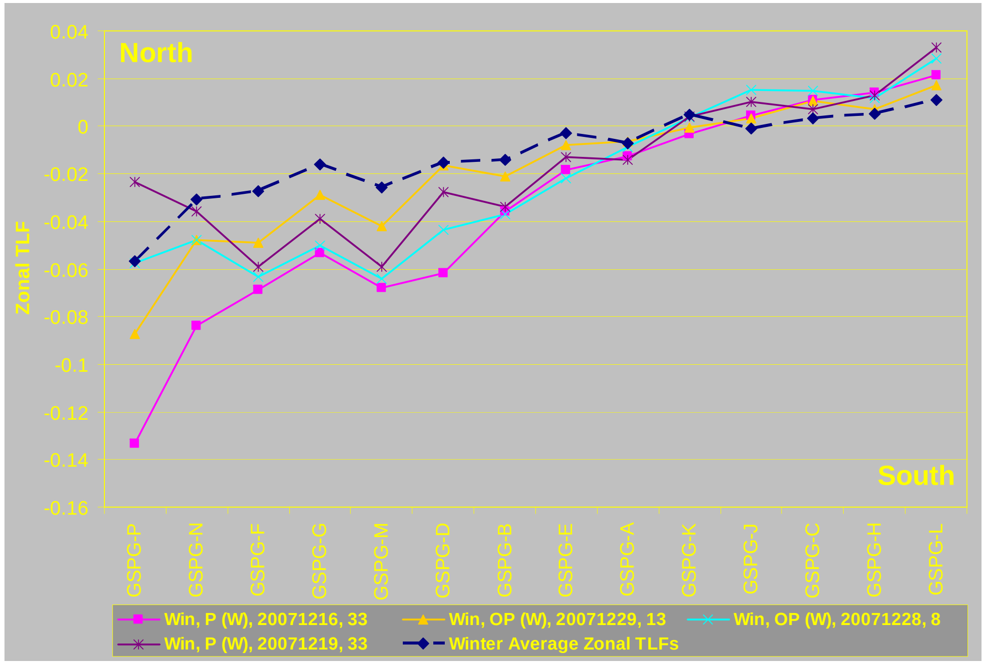

Figure 6: Illustrative variability of SSP Zonal TLFs on the basis of which the baseline Adjusted Seasonal Average Zonal TLFs were produced – Winter (keys: P – Peak; Off-P – Off Peak; W – Working; NW – Non Working)

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

For illustration, maximal and minimal Transmission Loss Multipliers (TLMs) for Delivering and for Off-taking are given as for peak SSP (based on Adjusted Winter Zonal TLFs) and for trough SSP (based on Adjusted Summer Zonal TLFs) – **Figure 7** and **Figure 8** respectively.

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

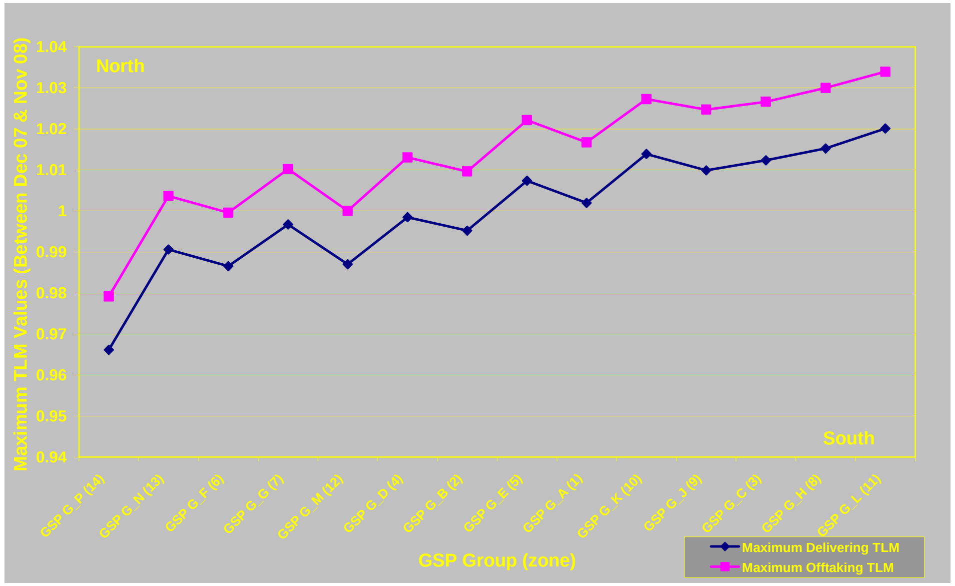

Figure 7: Illustrative Maximal Delivering and Off-taking TLMs for period December 2007 to November 2008 inclusively

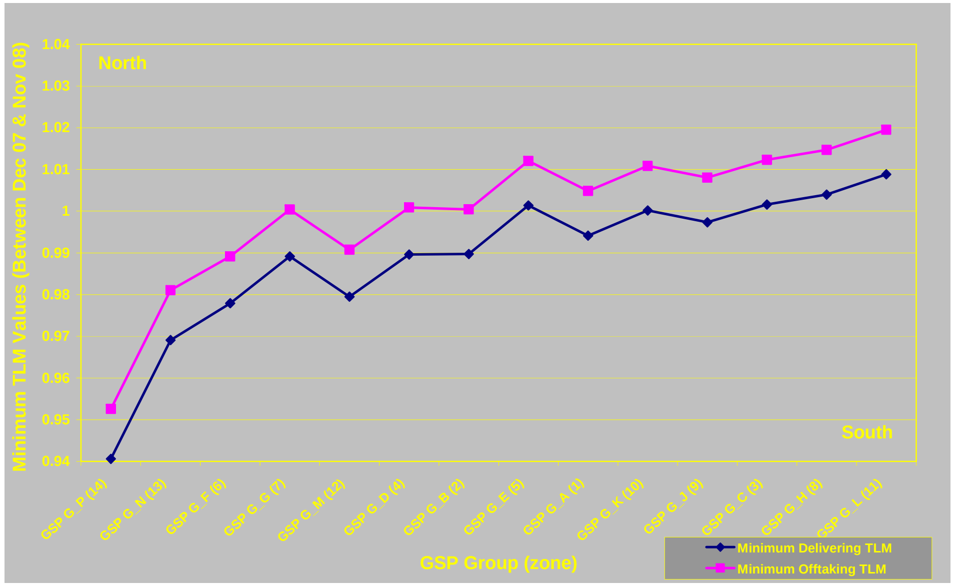

Figure 8: Illustrative Minimal Delivering and Off-taking TLMs for period December 2007 to November 2008 inclusively

Figure 9 illustrates Delivering and Off-Taking Average TLMs for the period between December 2007 and November 2008 inclusively. **Figure 10** illustrates Daily Average Delivering TLMs across the same period.

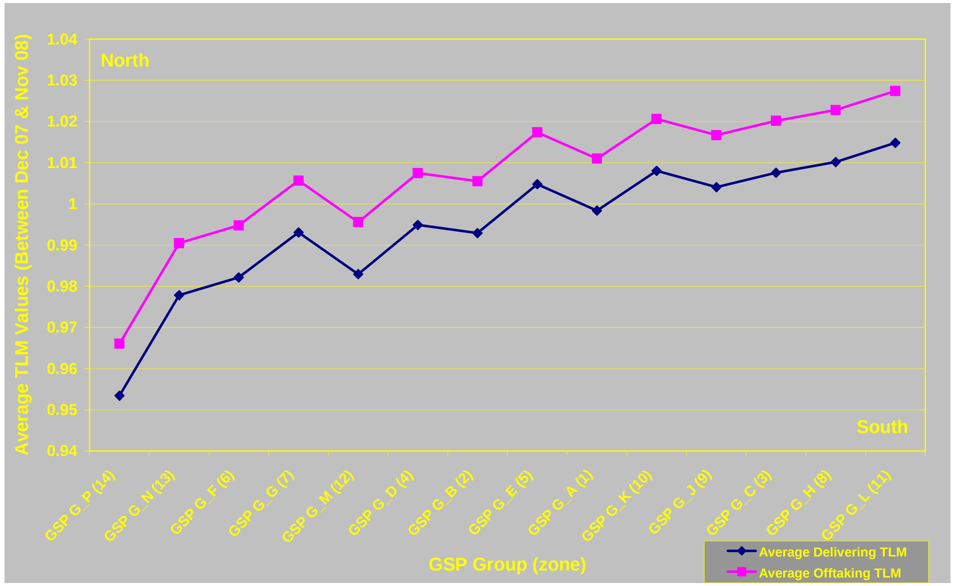

Figure 9: Illustrative Average Delivering and Off-taking TLMs for period December 2007 to November 2008 inclusively

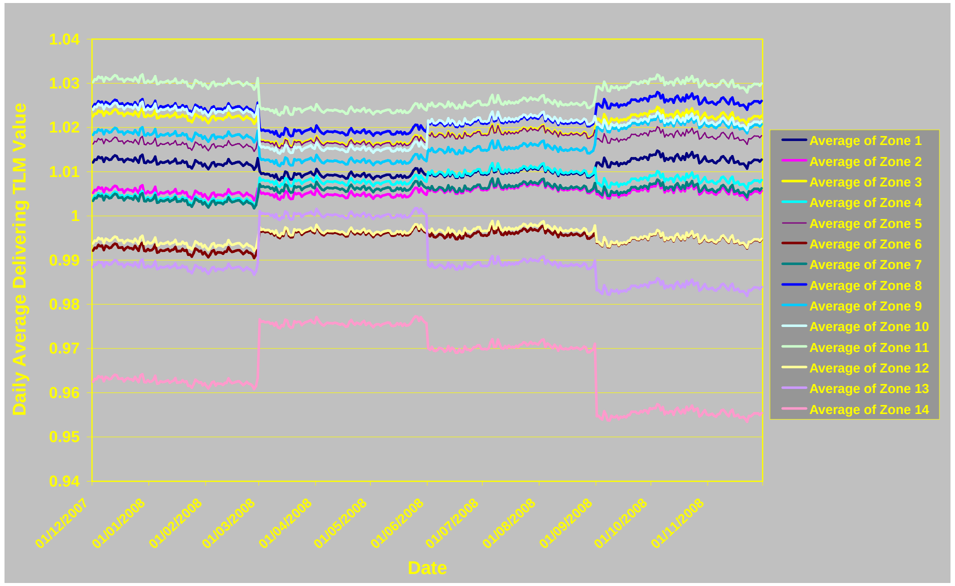

Figure 10: Illustrative Daily Average Delivering TLMs for the period December 2007 to November 2008 inclusively

Figure 10 is complemented with **Figure 11**, **Figure 12**, **Figure 13**, and **Figure 14** where baseline Delivering and Off-Taking Seasonal Peak and Trough TLMs are illustrated and compared with Seasonal Average Delivering and Off-Taking Seasonal TLMs that were calculated using the currently applied approach (i.e. that of using TLFs = 0).

Under MP229 TLMs would change and that change would be different in different geographical areas.

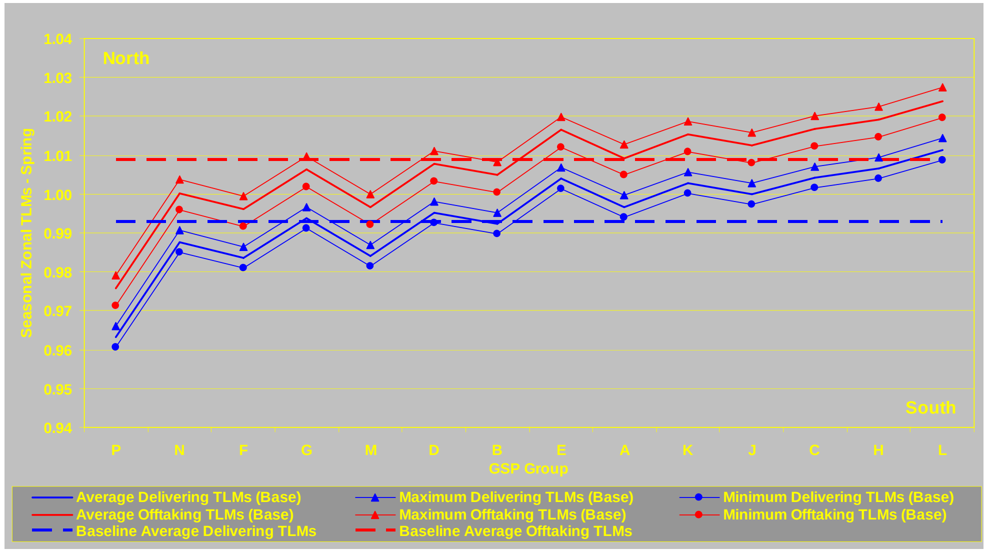

Figure 11: Baseline Delivering and Off-Taking Spring TLMs

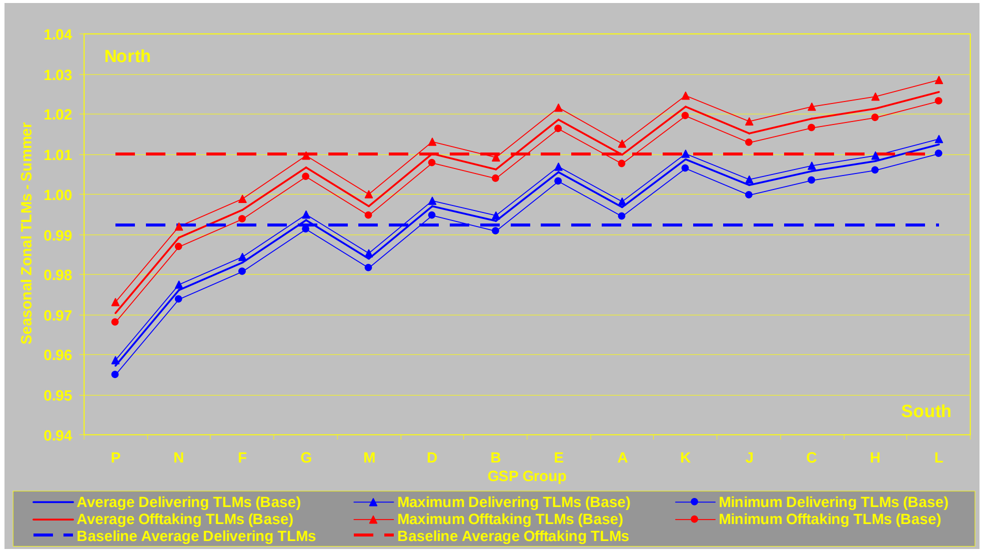

Figure 12: Baseline Delivering and Off-Taking Summer TLMs

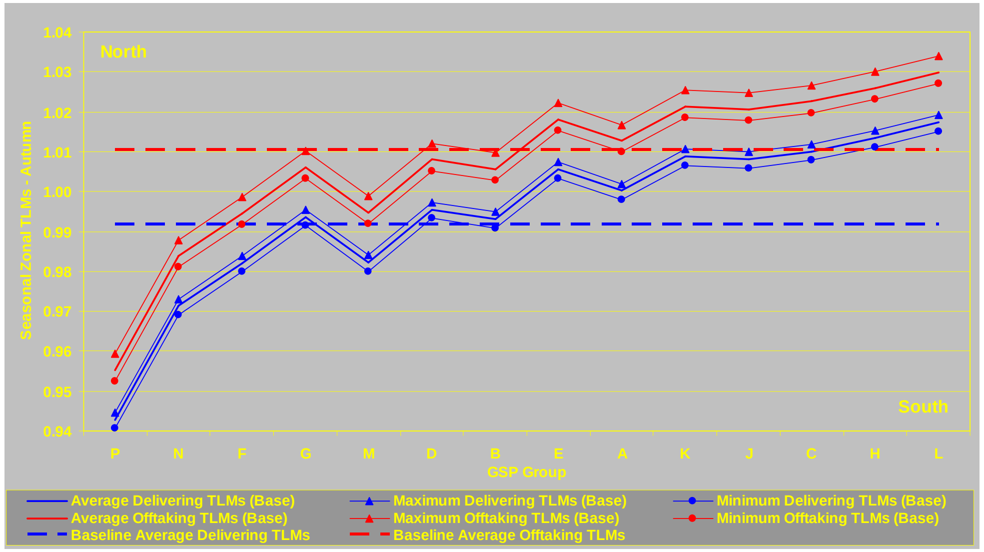

Figure 13: Baseline Delivering and Off-Taking Autumn TLMs

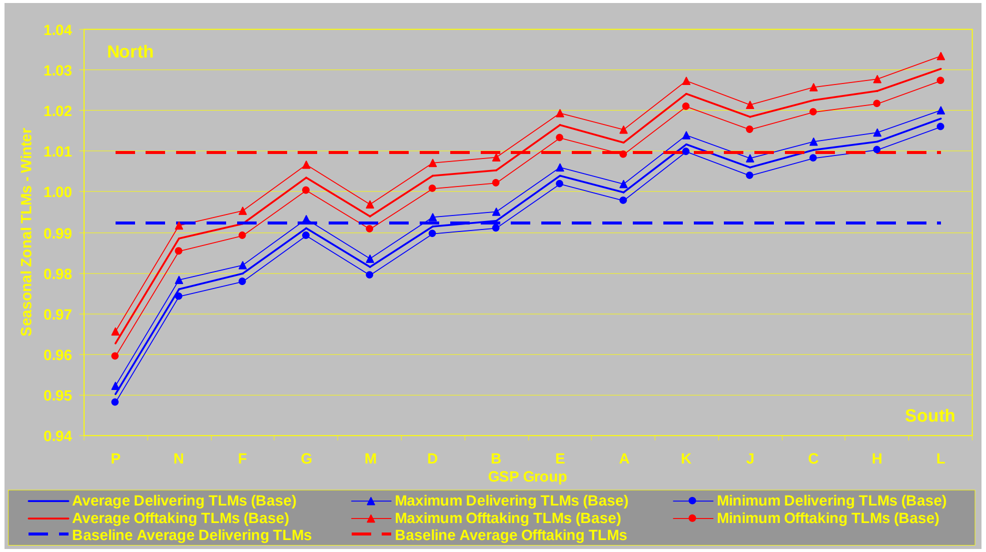

Figure 14: Baseline Delivering and Off-Taking Winter TLMs

5.3 Task 2: Considering temporal variability of TLFs

The outputs from this Task are:

- 1 set of Annual Adjusted Average Zonal TLFs; and
- 12 sets of Monthly Adjusted Average Zonal TLFs

This task was set with the following objectives:

- To compare the Task outputs to the baseline Seasonal Adjusted Average Zonal TLFs;
- To consider the extent to which Annual or Monthly Adjusted Average Zonal TLFs deviate from corresponding Seasonal Adjusted Average Zonal TLFs

5.3.1 Task 2: Annual Average Zonal TLFs

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

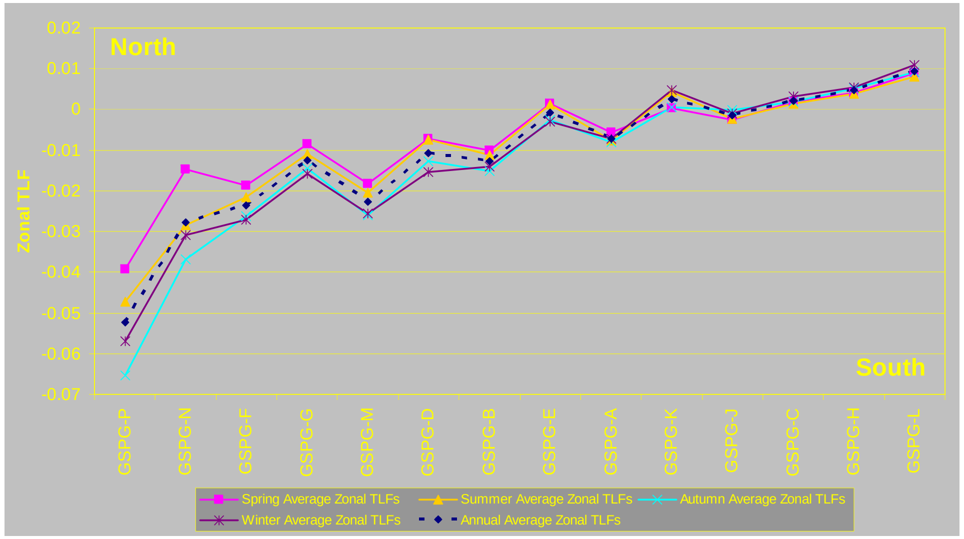

Figure 15: Adjusted Seasonal Average Zonal TLFs compared to the Adjusted Annual Average Zonal TLFs

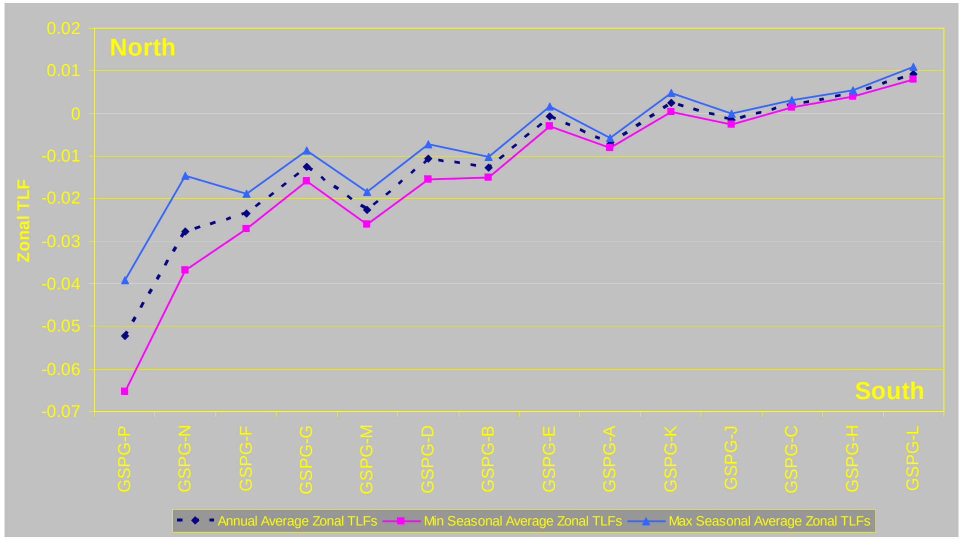

Figure 16: Envelope of variations of Adjusted Seasonal Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs

Annual Average Zonal TLFs signify a greater variability of Seasonal Average Zonal TLFs in the north than in the south.

For illustration, Delivering and Off-taking Zonal TLMs were calculated for annul peak SP and annual trough SP using appropriate Adjusted Seasonal Average Zonal TLFs. **Figure 17** illustrates these annual Delivering and Off-Taking TLMs calculated for the Peak and Trough SPs.

Table 5 lists Adjusted Annual Average Zonal TLFs that are presented in **Figure 15** and **Figure 16** and used for calculating Delivering and Off-Taking TLMs for the Peak and Trough SPs presented in **Figure 17**. The sign of the Adjusted Annual Average Zonal TLFs presented is explained in **5.2** in relation to Adjusted Seasonal Average Zonal TLFs presented in **Table 4**.

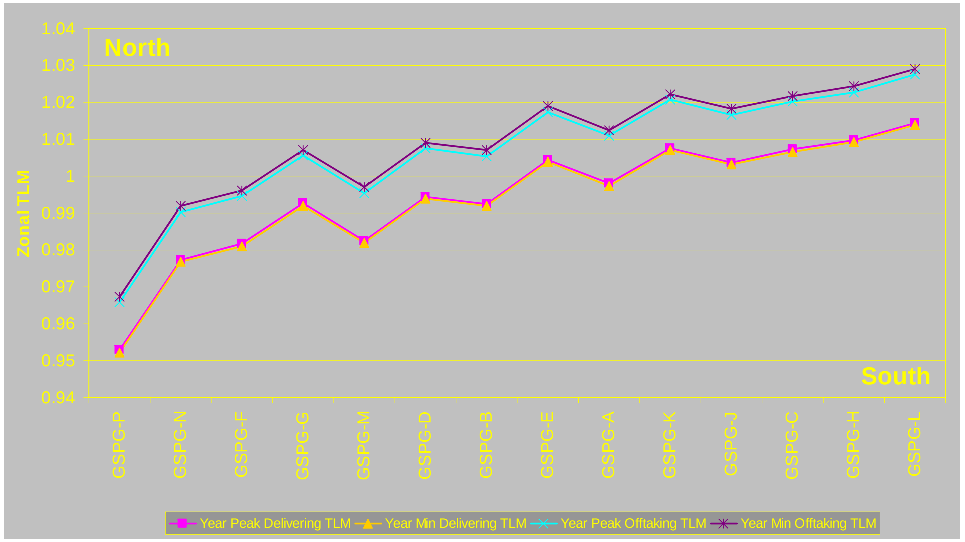

Figure 17: Annual Delivering and Off-Taking Peak and Trough TLMs

Table 5: Baseline Adjusted Annual Average Zonal TLFs

Zone	Annual Average Zonal TLFs
GSPG-P	-0.05234
GSPG-N	-0.02781
GSPG-F	-0.02348
GSPG-G	-0.01253
GSPG-M	-0.02268
GSPG-D	-0.01069
GSPG-B	-0.01269
GSPG-E	-0.00074
GSPG-A	-0.00719
GSPG-K	0.0025
GSPG-J	-0.00148
GSPG-C	0.00204
GSPG-H	0.00466
GSPG-L	0.00932

5.3.2 Task 2: Monthly Average Zonal TLFs

Figure 18 presents the Adjusted Monthly Average Zonal TLFs. **Figure 19** presents the envelope of variations of Adjusted Monthly Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs (envelope lines are not necessarily coincident with any monthly line).

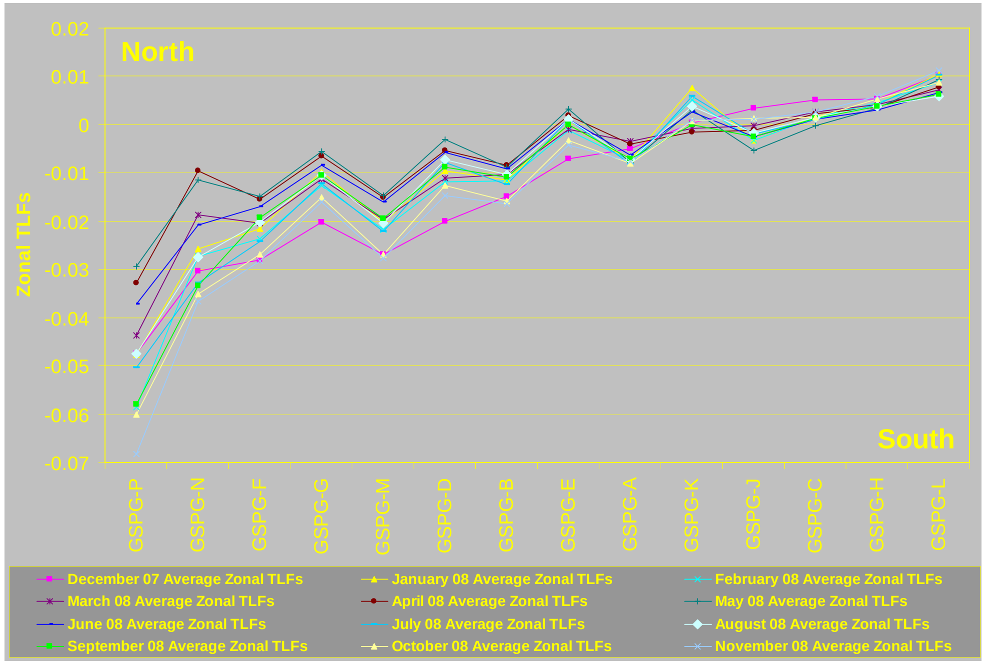

Figure 18: Adjusted Monthly Average Zonal TLFs

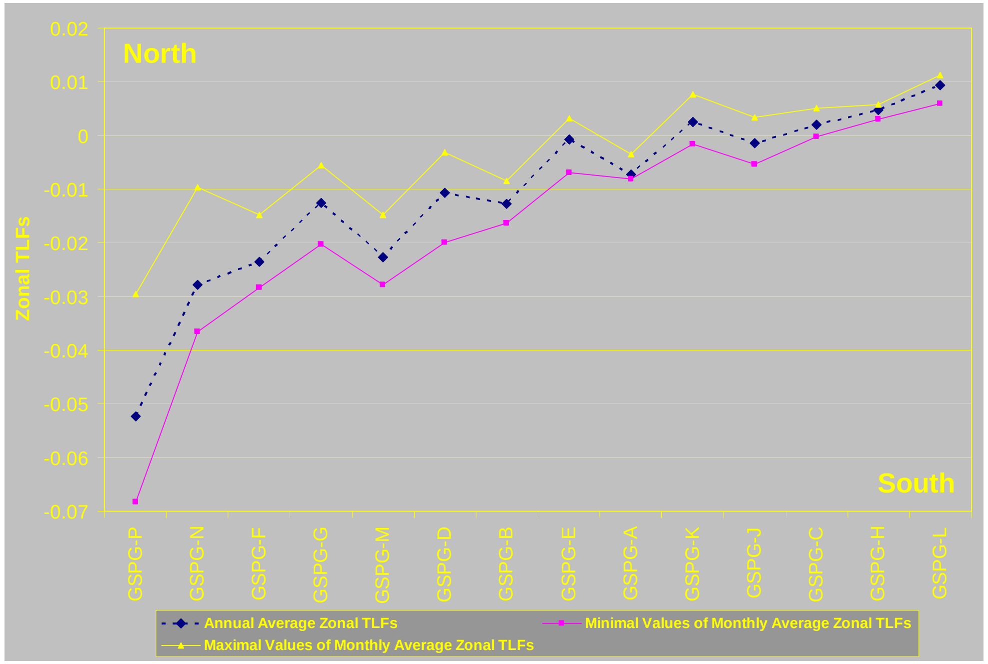

Figure 19: Envelope of variations of Adjusted Monthly Average Zonal TLFs around the Adjusted Annual Average Zonal TLFs

Table 6 lists Adjusted Monthly Average Zonal TLFs that are presented in **Figure 18**. The sign of the Adjusted Annual Average Zonal TLFs presented is explained in **5.2** in relation to Adjusted Seasonal Average Zonal TLFs presented in **Table 4**.

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

Table 6: Monthly Adjusted Seasonal Average TLFs in tabular format

Zone	December 07 Average Zonal TLFs	January 08 Average Zonal TLFs	February 08 Average Zonal TLFs	March 08 Average Zonal TLFs	April 08 Average Zonal TLFs	May 08 Average Zonal TLFs	June 08 Average Zonal TLFs	July 08 Average Zonal TLFs	August 08 Average Zonal TLFs	September 08 Average Zonal TLFs	October 08 Average Zonal TLFs	November 08 Average Zonal TLFs
GSPG-P	-0.04758	-0.04766	-0.05865	-0.04366	-0.03286	-0.02948	-0.03715	-0.05039	-0.04757	-0.05795	-0.06014	-0.06834
GSPG-N	-0.03031	-0.02585	-0.02729	-0.01863	-0.00961	-0.01139	-0.02089	-0.03282	-0.02752	-0.03333	-0.03504	-0.03663
GSPG-F	-0.02798	-0.02159	-0.02367	-0.02043	-0.01546	-0.01488	-0.0169	-0.02422	-0.02024	-0.01931	-0.027	-0.0283
GSPG-G	-0.02031	-0.00969	-0.01268	-0.0112	-0.00656	-0.00555	-0.00839	-0.01221	-0.01043	-0.01051	-0.01501	-0.01609
GSPG-M	-0.02693	-0.02018	-0.02181	-0.01975	-0.01513	-0.01475	-0.01606	-0.02206	-0.02046	-0.01953	-0.02687	-0.02775
GSPG-D	-0.02002	-0.00949	-0.01189	-0.01101	-0.00533	-0.00307	-0.00582	-0.00789	-0.00734	-0.00883	-0.01267	-0.01477
GSPG-B	-0.01489	-0.01138	-0.01174	-0.01027	-0.0084	-0.0087	-0.00913	-0.01248	-0.01033	-0.01095	-0.0159	-0.01635
GSPG-E	-0.00699	0.00007	-0.00119	-0.00105	0.00192	0.00328	0.00114	0.00114	0.00105	-0.00011	-0.0032	-0.0043
GSPG-A	-0.00506	-0.00719	-0.0074	-0.0035	-0.00397	-0.00789	-0.0064	-0.00816	-0.00727	-0.00706	-0.00811	-0.00768
GSPG-K	0.00028	0.00767	0.00506	-0.00077	-0.00159	0.00309	0.00273	0.0058	0.00376	0.00007	0.0008	0.00096
GSPG-J	0.00338	-0.00323	-0.00317	-0.00029	-0.0011	-0.00534	-0.00253	-0.00197	-0.00179	-0.00251	0.00126	0.00113
GSPG-C	0.00517	0.0017	0.00158	0.00271	0.00234	-0.00025	0.00116	0.00121	0.00145	0.00123	0.00156	0.0026
GSPG-H	0.00541	0.00442	0.00453	0.00424	0.00357	0.00337	0.00309	0.00412	0.00386	0.00383	0.00533	0.00582
GSPG-L	0.01023	0.01053	0.00871	0.00725	0.00778	0.00929	0.00667	0.01023	0.00597	0.00619	0.00881	0.01132

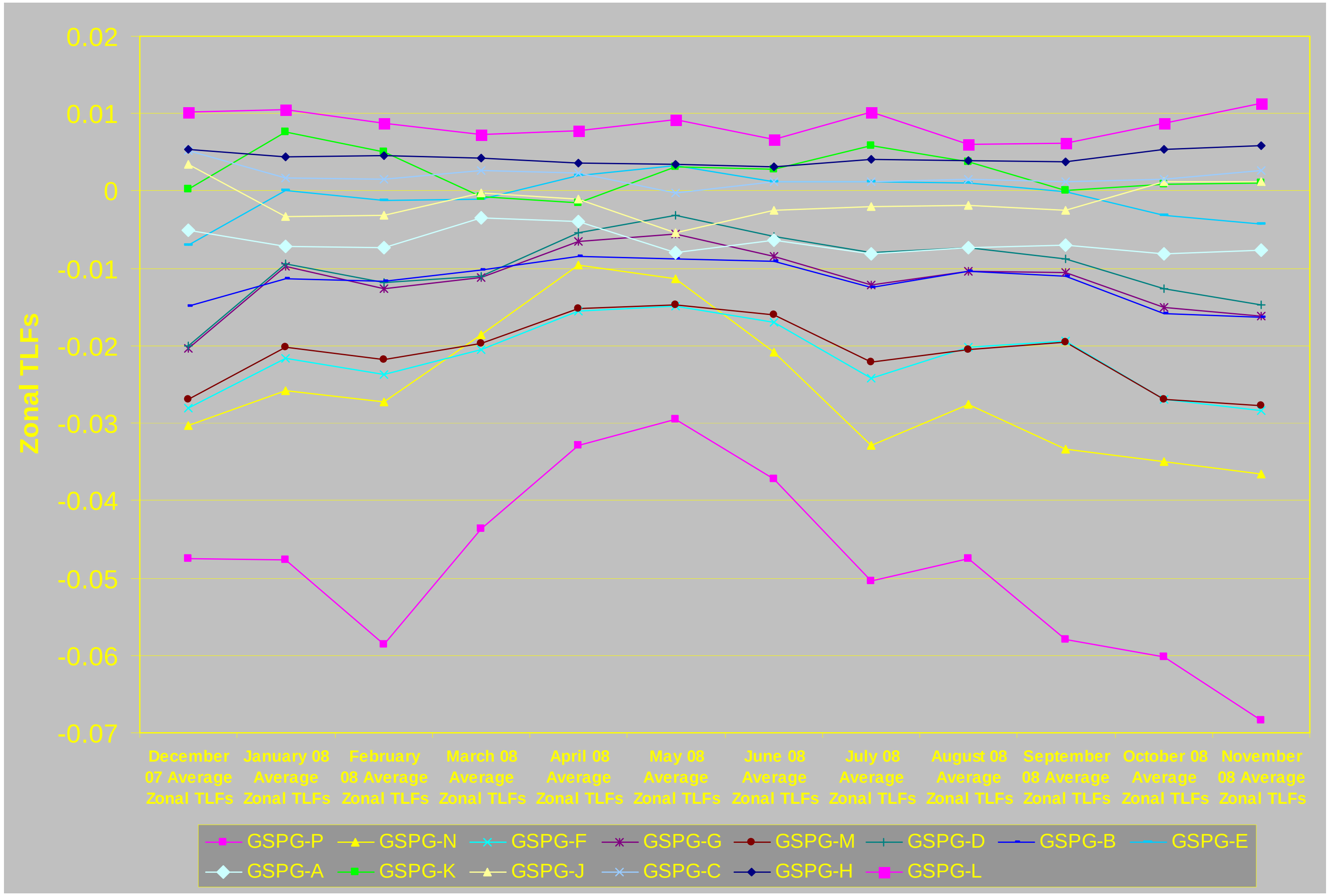

Figure 20: Fluctuation of Adjusted Monthly Average Zonal TLFs for each zone, over the considered months

Figure 20 presents for each zone the fluctuation of the Adjusted Monthly Average Zonal TLFs over the considered months.

Similarly as **Figure 18**, **Figure 20** also demonstrates a greater variability of Adjusted Monthly Average Zonal TLFs in the north than in the south.

Figure 21, **Figure 23**, **Figure 25**, and **Figure 27** 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 22**, **Figure 24**, **Figure 26**, and **Figure 28** 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 necessarily coincident with any particular monthly line). The envelopes around the Adjusted Seasonal Average Zonal TLFs are much narrower than the envelope around the Adjusted Annual Average Zonal TLFs (**Figure 19**).

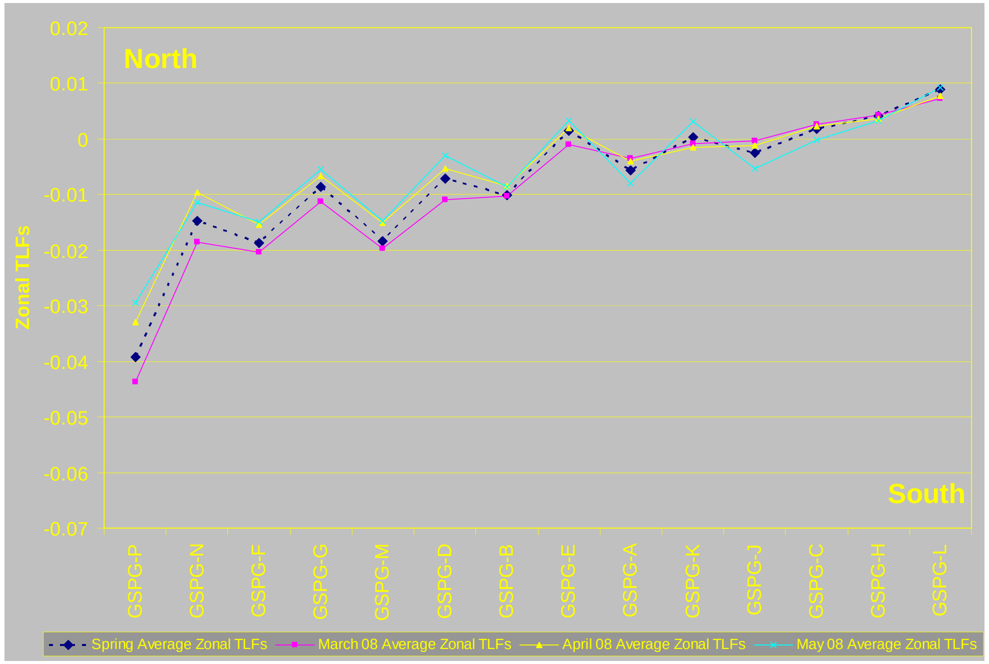

Figure 21: Adjusted Monthly Average Zonal TLFs for <u>Spring</u> months compared to the <u>Spring</u> Adjusted Seasonal Average Zonal TLFs

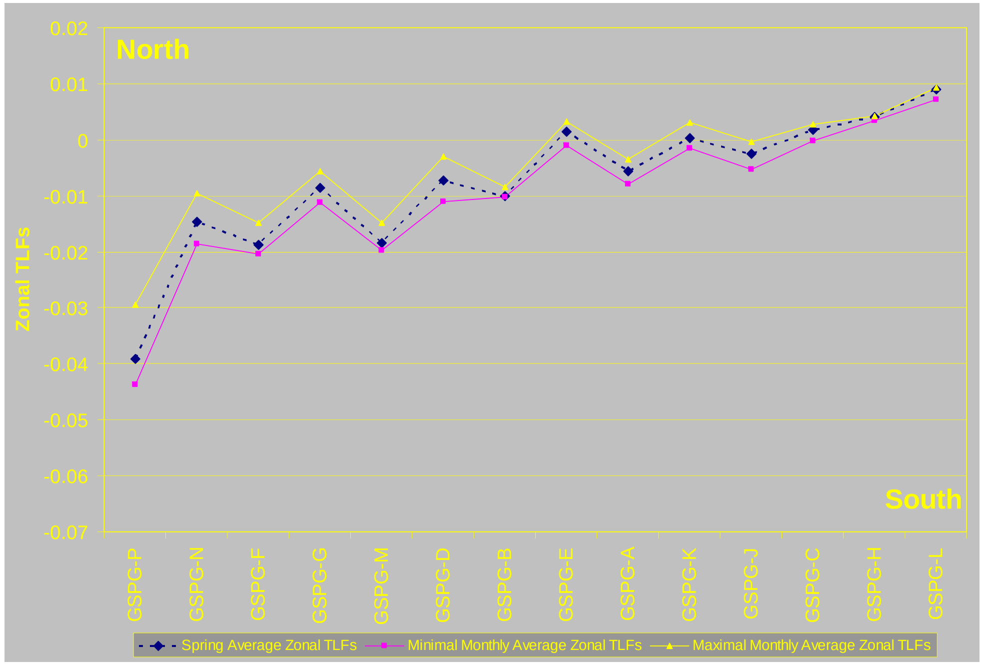

Figure 22: Envelope of variations of Adjusted Monthly Average Zonal TLFs for <u>Spring</u> months around the <u>Spring</u> Adj. Seasonal Average Zonal TLFs

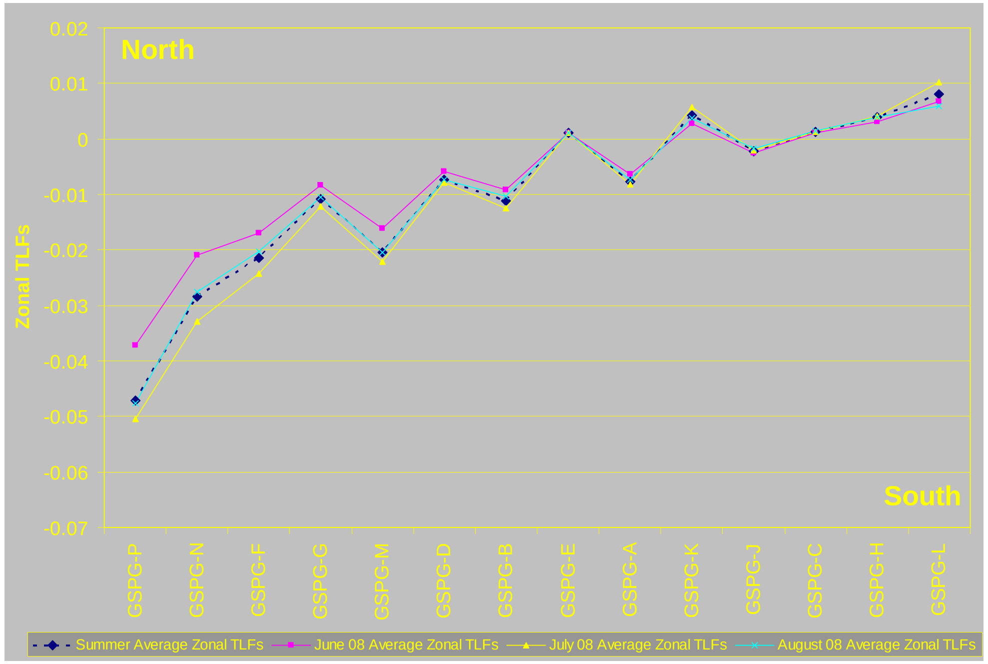

Figure 23: Adjusted Monthly Average Zonal TLFs for Summer months compared to the Summer Adjusted Seasonal Average Zonal TLFs

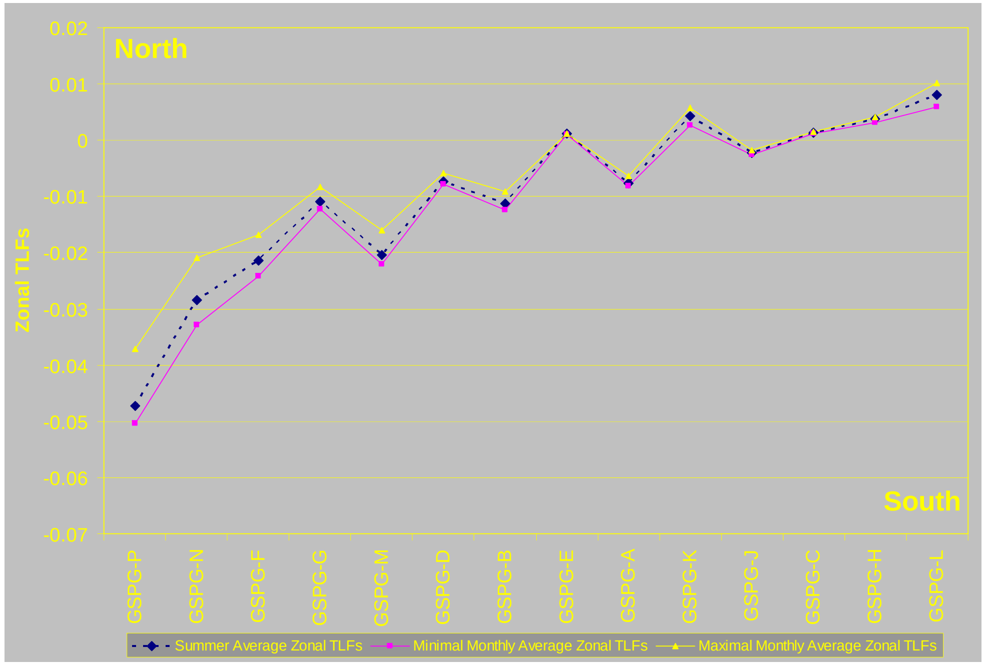

Figure 24: Envelope of variations of Adjusted Monthly Average Zonal TLFs for Summer months around the Summer Adj. Seasonal Average Zonal TLFs

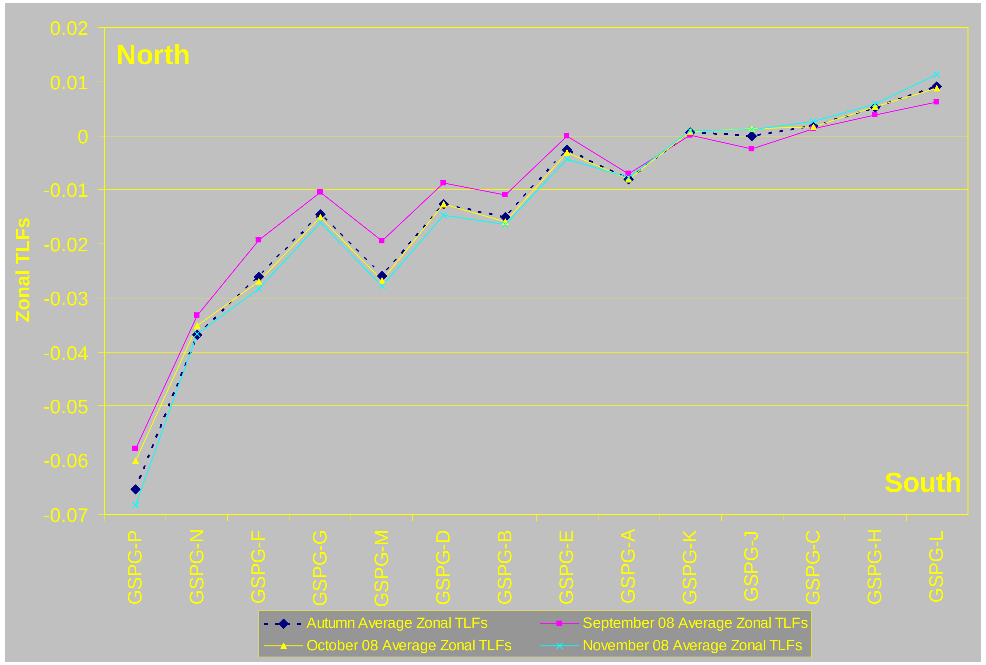

Figure 25: Adjusted Monthly Average Zonal TLFs for Autumn months compared to the Autumn Adjusted Seasonal Average Zonal TLFs

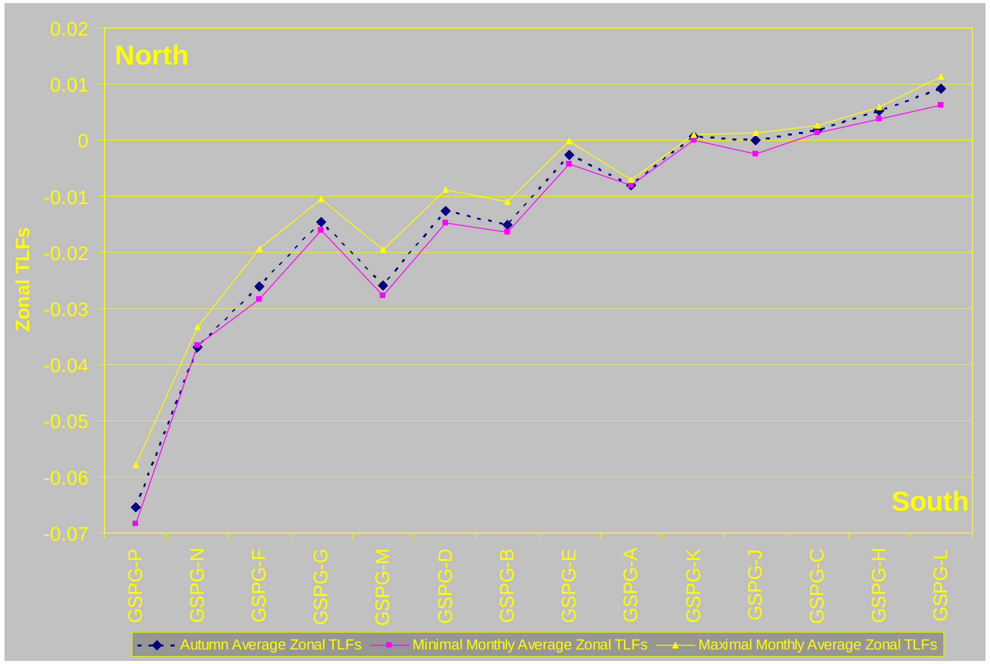

Figure 26: Envelope of variations of Adjusted Monthly Average Zonal TLFs for Autumn months around the Autumn Adj. Seasonal Average Zonal TLFs

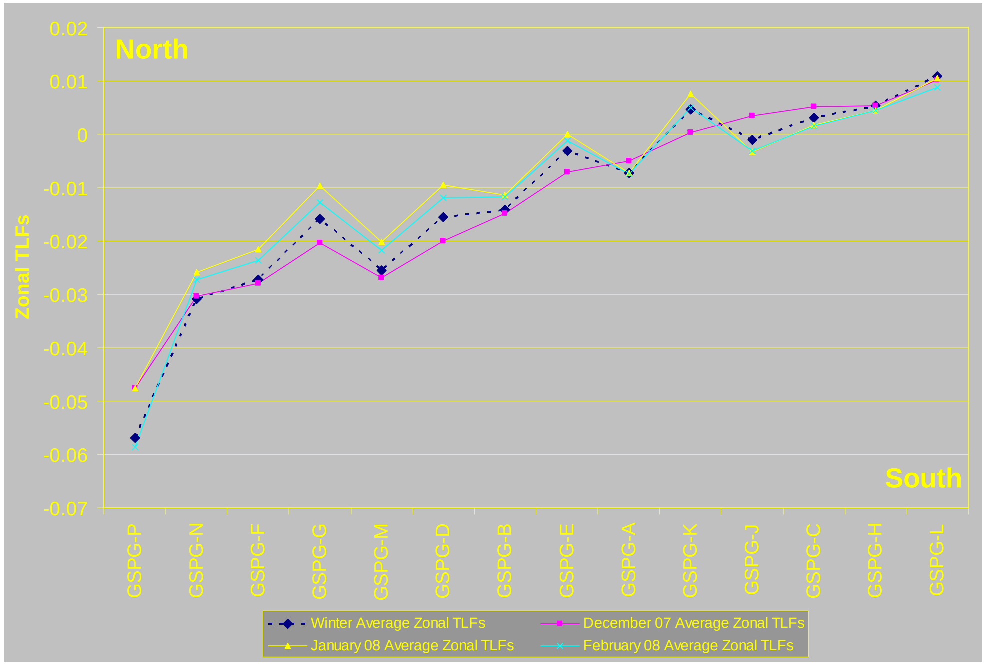

Figure 27: Adjusted Monthly Average Zonal TLFs for Winter months compared to the Winter Adjusted Seasonal Average Zonal TLFs

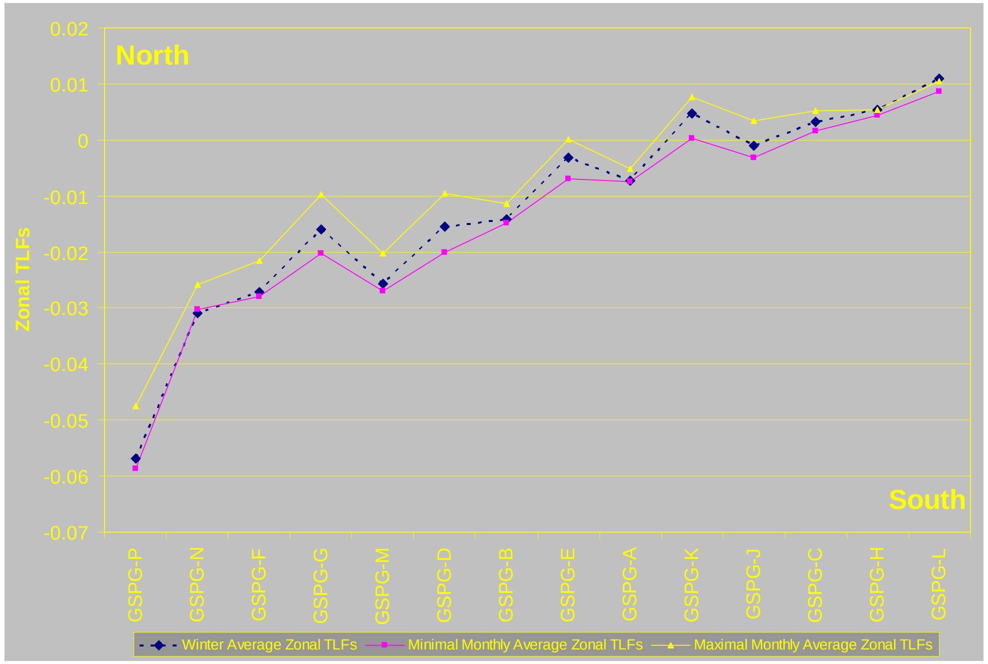

Figure 28: Envelope of variations of Adjusted Monthly Average Zonal TLFs for Winter months around the Winter Adj. Seasonal Average Zonal TLFs

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

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

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

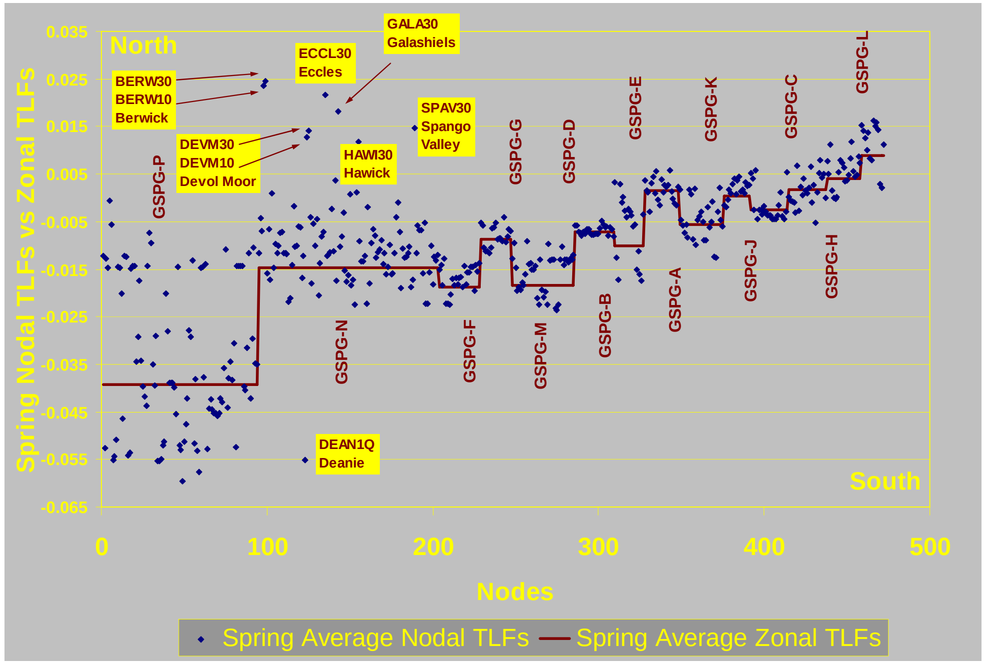

Figure 29: Comparison of Adjusted Seasonal Average Nodal TLFs with Adjusted Seasonal Average Zonal TLFs for Spring

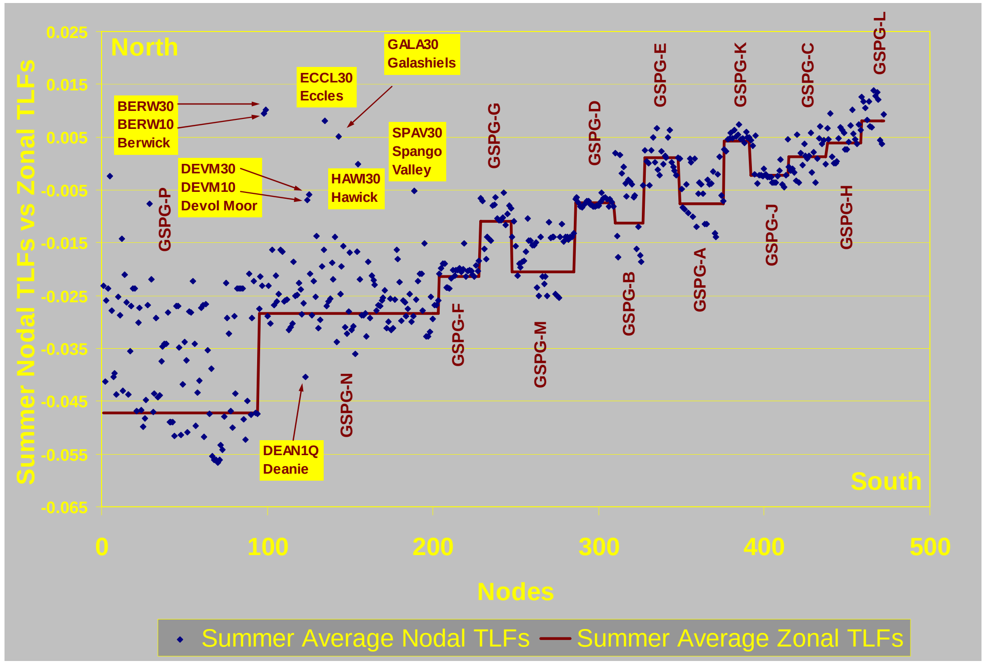

Figure 30: Comparison of Adjusted Seasonal Average Nodal TLFs with Adjusted Seasonal Average Zonal TLFs for Summer

Figure 29, **Figure 30**, **Figure 31**, and **Figure 32** present comparison of Adjusted Seasonal Average Nodal TLFs to Adjusted Seasonal Average Zonal TLFs for spring, summer, autumn and winter respectively. It should be noted that the Adjusted Seasonal Average Zonal TLFs were not derived directly from respective Adjusted Seasonal Average Nodal TLFs. Adjusted Seasonal Average Nodal/Zonal TLFs were derived from ½ h Nodal/Zonal TLFs respectively.

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

From the results presented it can be observed that introduction of Modification Proposal P229 and its Zonal TLFs/TLMs (based on GSPG zones) could result in Nodal TLFs for some nodes being closer to neighbouring Zonal TLFs.

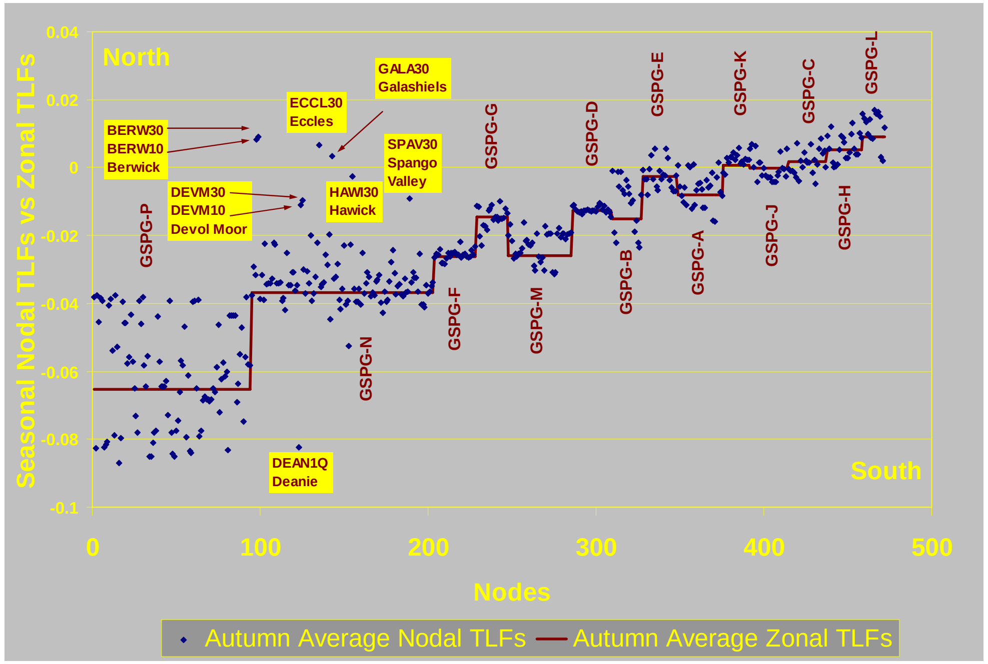

Figure 31: Comparison of Adjusted Seasonal Average Nodal TLFs with Adjusted Seasonal Average Zonal TLFs for Autumn

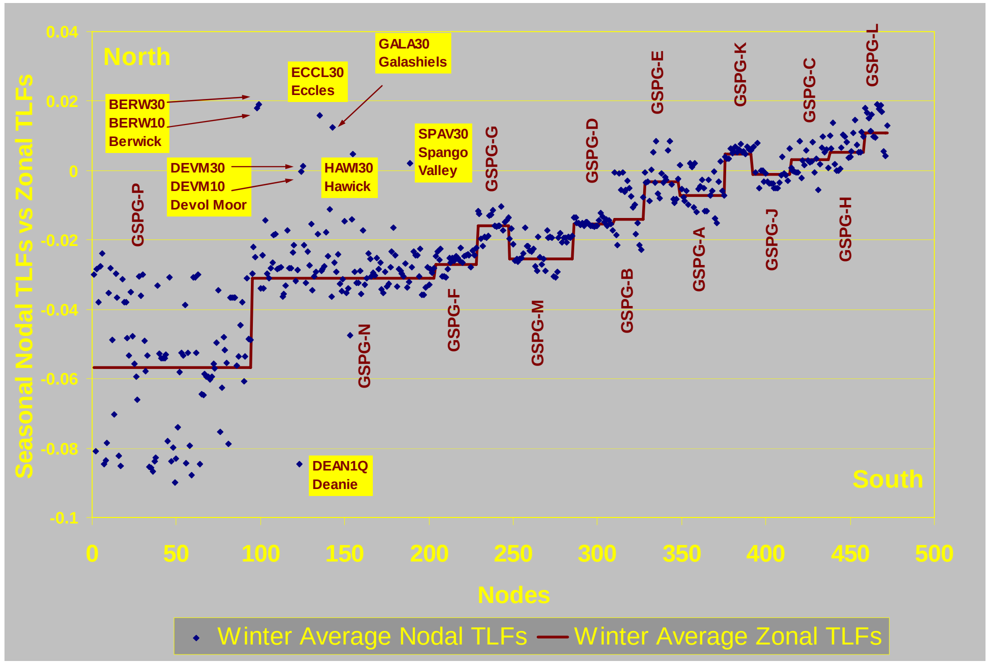

Figure 32: Comparison of Adjusted Seasonal Average Nodal TLFs with Adjusted Seasonal Average Zonal TLFs for Winter

The P229 Modification Group noted 9 outliers among Adjusted Seasonal Average Nodal TLFs (**Figure 29**, **Figure 30**, **Figure 31**, and **Figure 32**) and requested that these nodes are identified. One node was identified as DEAN1Q (Deanie), 132 kV node with hydro generation that was erroneously allocated to GSPG-N instead to GSPG-P in the Network Mapping Statement input data given to Siemens PTI. Impact of this error on the overall results in this project is considered negligible. The other 8 nodes were identified as listed in **Table 7** and geographically located in **Figure 33**.

Table 7: Monthly Adjusted Seasonal Average TLFs in tabular format

Node	Full name	Voltage	Node	Full name	Voltage
BERW30	Berwick	33 kV	DEVM30	Devol Moor	33 kV
BERW10	Berwick	132 kV	DEVM10	Devol Moor	132 kV
ECCL30	Eccles	33 kV	GALA30	Galashiels	33 kV
HAWI30	Hawick	33 kV	SPAV30	Spango Valley	33 kV

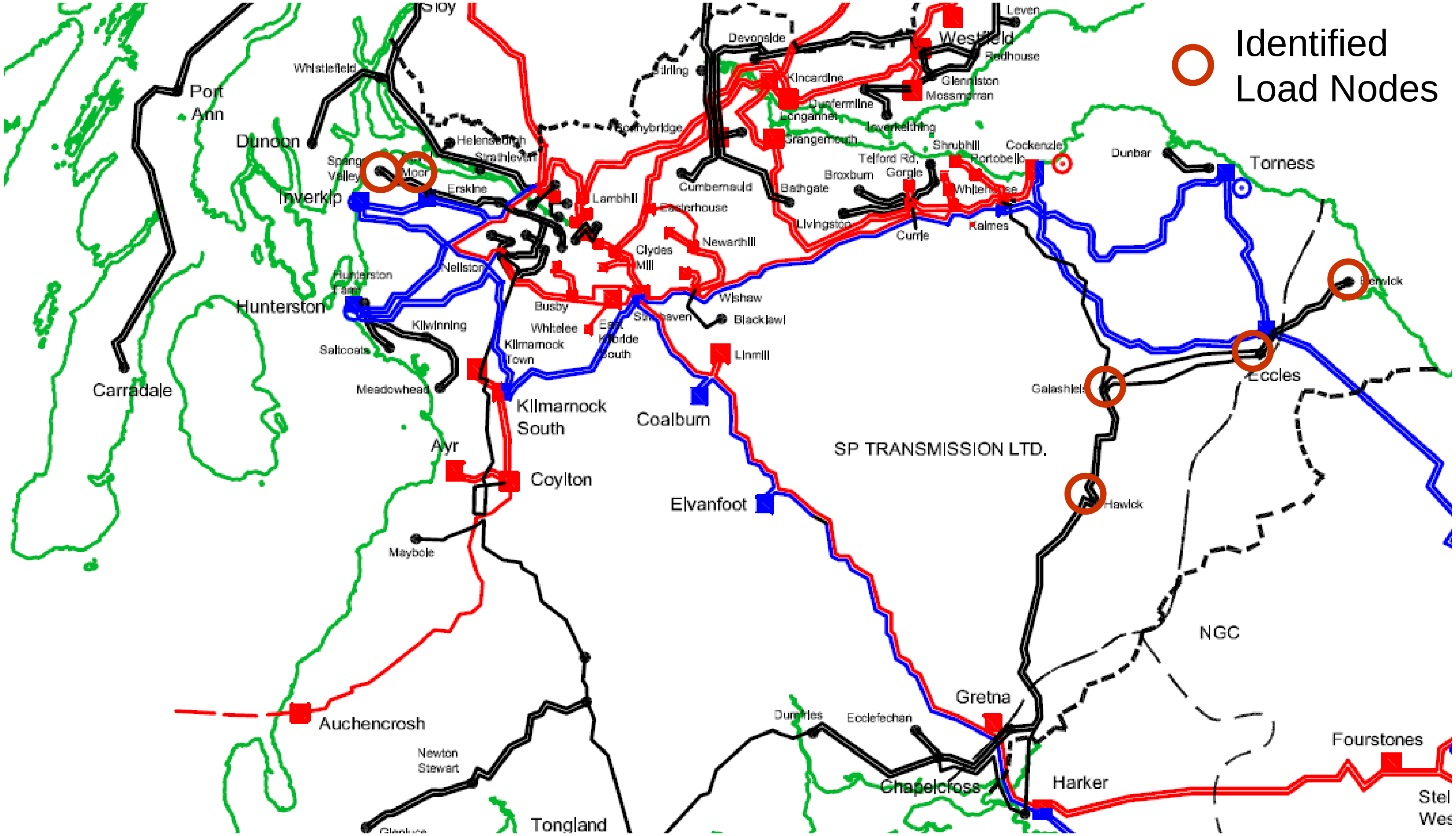

Figure 33: Geographical locations of the nodes considered to have outlying Adjusted Seasonal Average Nodal TLFs in GSPG N (Figure 29, Figure 30, Figure 31, and Figure 32)

One of the main factors influencing the Nodal TLFs' level is the "electrical location" in the transmission system (often correlated to the geographical location). The eight load nodes listed in **Table 7** are "deep" in 132 kV network and their TLFs are consistent with their off-taking contributing to increasing the system heating losses.

5.5 Task 4: Examine sensitivity to flows on French and Moyle Interconnectors

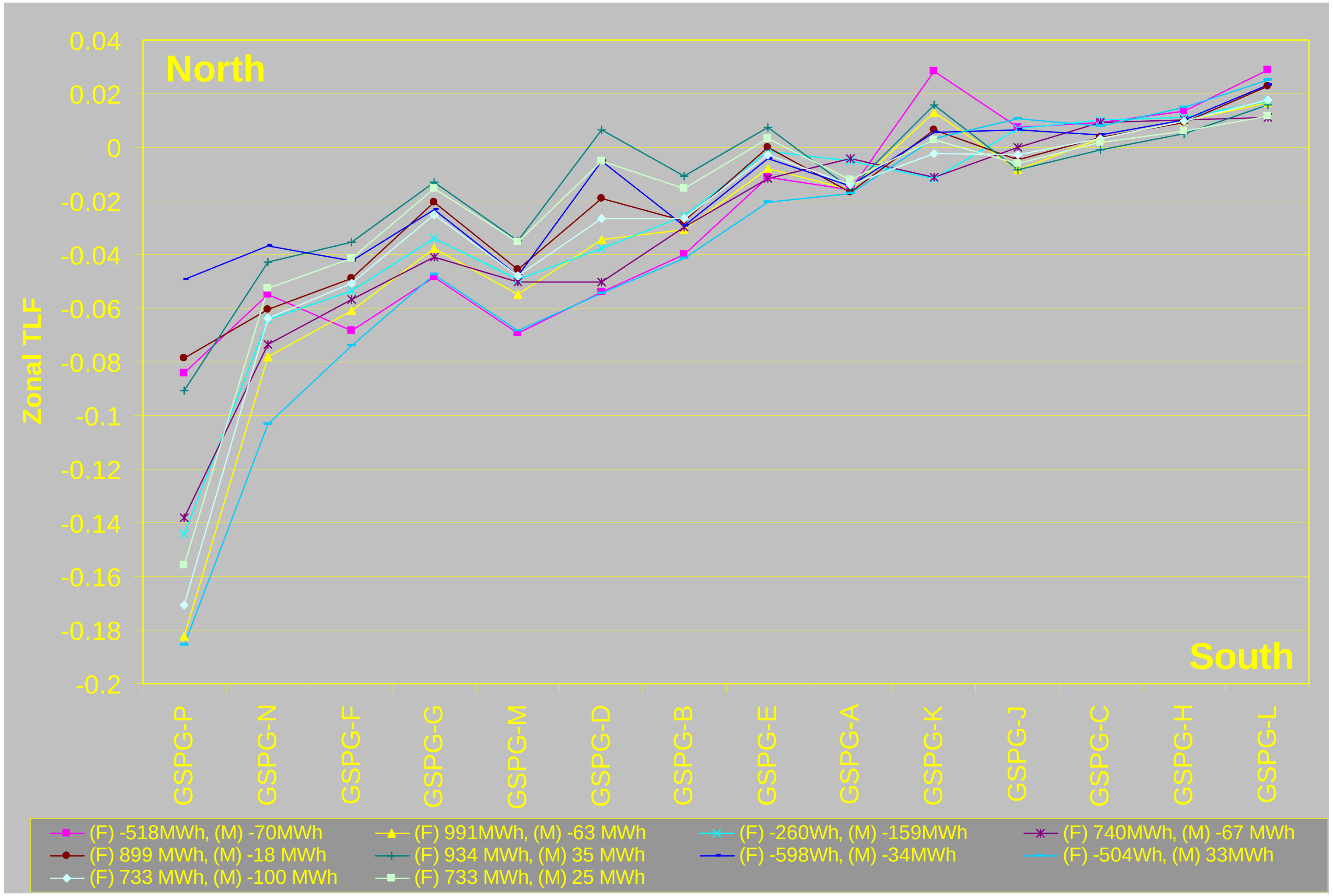

Figure 34: Comparison of Adjusted SSP Zonal TLFs for a number of different operational regimes on the French and Moyle Interconnections

A number of SSPs in Task 1 input/output data set were identified as different indicative operation regimes on the French and Moyle interconnections. These SSPs and the operating conditions on the French and Moyle interconnections are listed in **Table 8**. It should be noted that not all desired operating combinations for the French and Moyle interconnections were available among the 630 SSPs selected for this project (as indicated in **Table 8**)

Figure 36 presents the Adjusted SSP Zonal TLFs for different delivering and off-taking regimes on French and Moyle interconnections (as listed in **Table 8**)

Table 8: Different delivering/off-taking regimes on the French and Moyle interconnections considered

Season	Date	SSP	France		Moyle		French Status	Moyle Status
			Vol MWh	% load-ing	Vol MWh	% load-ing		
Winter	20080213	17	-518	52%	-70	28%	Off-Taking	Off-Taking
Winter	Combination unavailable						Off-Taking	Delivering
Winter	20080223	42	991	99%	-63	25%	Delivering	Off-Taking
Winter	Combination unavailable						Delivering	Delivering
Spring	20080403	17	-260	26%	-159	64%	Off-Taking	Off-Taking
Spring	Combination unavailable						Off-Taking	Delivering
Spring	20080315	42	740	74%	-67	26%	Delivering	Off-Taking
Spring	Combination unavailable						Delivering	Delivering
Summer	Combination unavailable						Off-Taking	Off-Taking
Summer	Combination unavailable						Off-Taking	Delivering
Summer	20080630	18	899	90%	-18	7%	Delivering	Off-Taking
Summer	20080729	11	934	93%	35	88%	Delivering	Delivering
Autumn	20081128	4	-598	60%	-34	14%	Off-Taking	Off-Taking
Autumn	20081028	27	-504	50%	33	83%	Off-Taking	Delivering
Autumn	20081115	42	733	73%	-100	40%	Delivering	Off-Taking
Autumn	20081115	12	733	73%	25	63%	Delivering	Delivering

Figure 35, **Figure 36**, **Figure 37**, and **Figure 38** present selected Adjusted SSP Zonal TLFs compared to appropriate Adjusted Seasonal Average Zonal TLFs for spring, summer, autumn and winter respectively.

In line with the findings in Task 5, Task 7 and Task 8, and as demonstrated with the results of this Task 4, it can be expected that different flows on French and Moyle interconnections influence the Zonal TLFs. However, various combinations and levels of flows on French and Moyle interconnections are captured and represented in the selected SSPs and their Metered Volumes used in the project so that their influence was accounted for and averaged in calculation of Adjusted Seasonal Average Zonal TLFs.

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

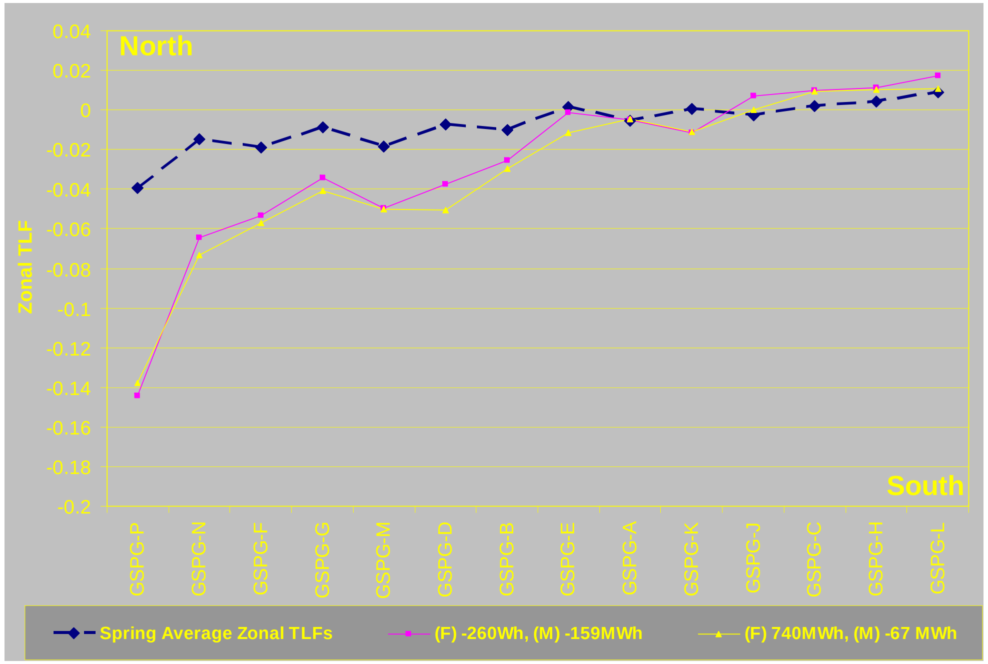

Figure 35: Comparison of Adjusted SSP Zonal TLFs for different operational regimes on the French and Moyle Interconnections put against the Spring Adjusted Seasonal Average Zonal TLFs

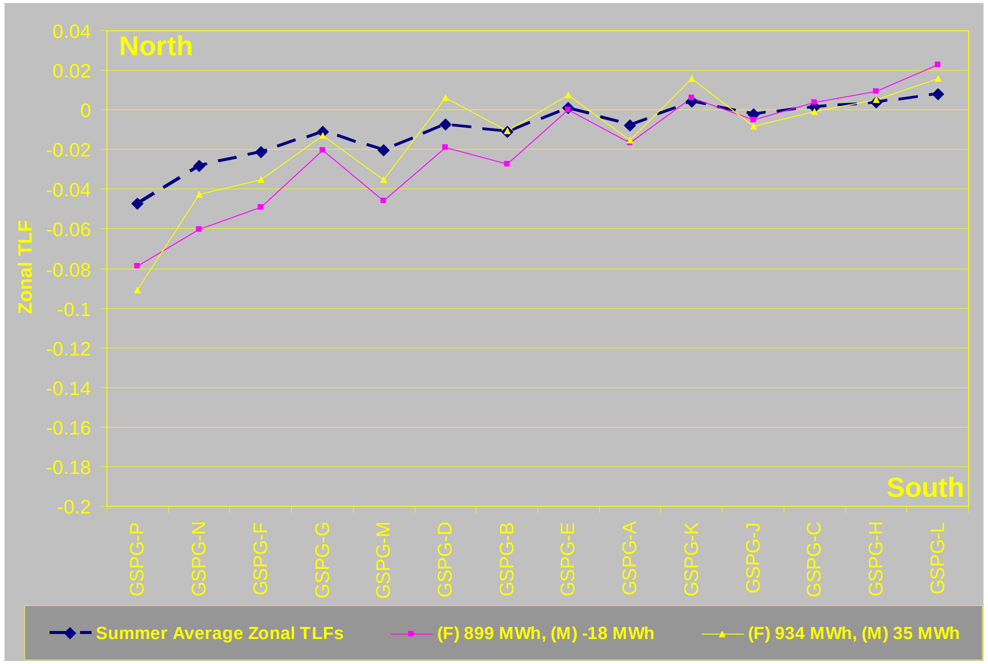

Figure 36: Comparison of Adjusted SSP Zonal TLFs for different operational regimes on the French and Moyle Interconnections put against the Summer Adjusted Seasonal Average Zonal TLFs

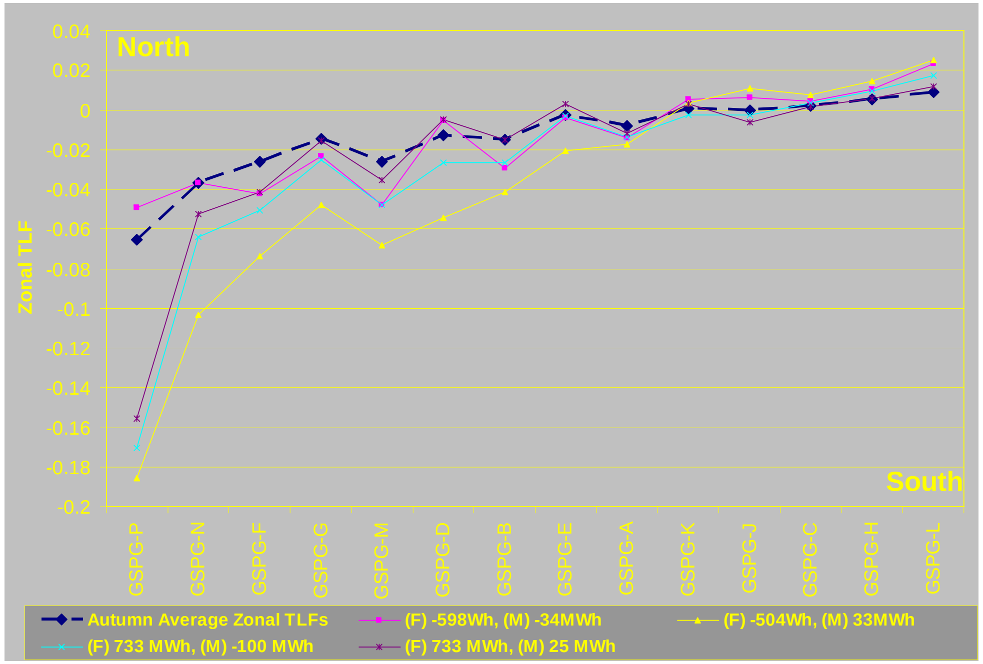

Figure 37: Comparison of Adjusted SSP Zonal TLFs for different operational regimes on the French and Moyle Interconnections put against the Autumn Adjusted Seasonal Average Zonal TLFs

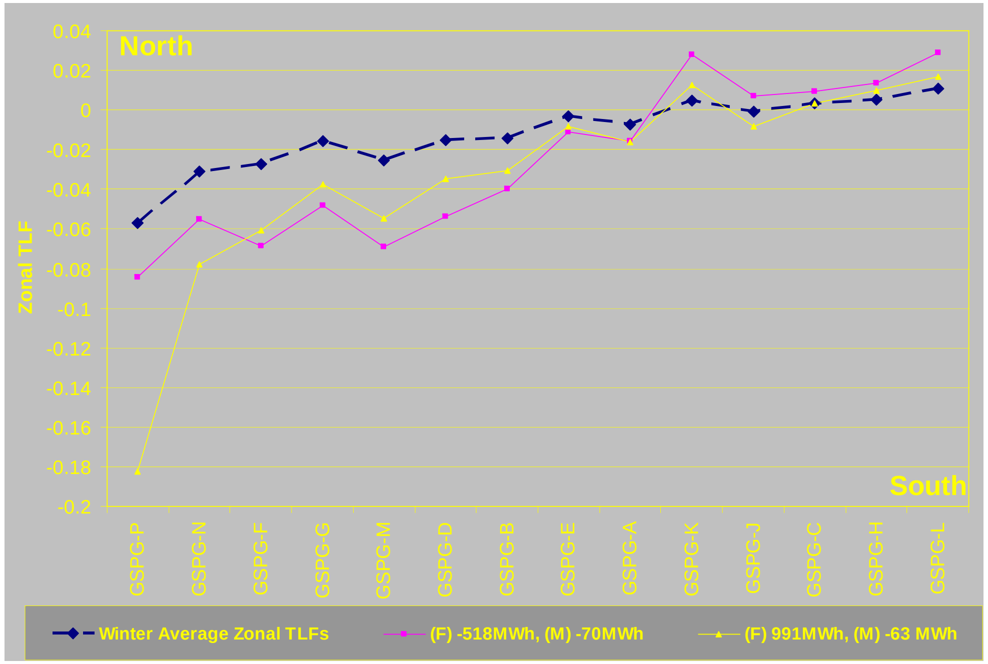

Figure 38: Comparison of Adjusted SSP Zonal TLFs for different operational regimes on the French and Moyle Interconnections put against the Winter Adjusted Seasonal Average Zonal TLFs

5.6 Task 5: Examine sensitivity of Seasonal Zonal TLFs to participants responding to signals

In order to model the impact of relocating generation, the output of a number of BM Units across the 630 SSPs from 2 different geographical locations (thus forming 2 different cases – see **Table 9**) were relocated to the Kingsnorth Node (KINO41). The Adjusted Seasonal Average Zonal TLFs were calculated for each of the two cases and compared to the baseline Adjusted Seasonal Average Zonal TLFs

Figure 39, **Figure 40**, **Figure 41**, and **Figure 42** present the Adjusted Seasonal Average Zonal TLFs calculated separately for each of the two cases described above and compared to the baseline Adjusted Seasonal Average Zonal TLFs for spring, summer, autumn and winter respectively. It can be observed that relocating Draxx has a notable impact on the Adjusted Seasonal Average Zonal TLFs. Relocating Killingholme (T_KILLPG-2 part) has an impact on the Adjusted Seasonal Average Zonal TLFs but it is a less obvious one. This can be explained to be due to substantially different size of these two generation plants.

Figure 43, **Figure 44**, **Figure 45**, and **Figure 46** present illustrative TLM values for the two above cases (DRAX and KILL) for seasonal peak and trough for spring, summer, autumn and winter respectively.

Table 9: Two cases of participants responding to signals

From Location	BMU ID(s)	From Node(s)	From GSP Zone	To Node	To GSP Zone
Draxx (case 1: DRAX – 3,945MW)	T_DRAXX-1 T_DRAXX-2 T_DRAXX-3 T_DRAXX-9G T_DRAXX-10G T_DRAXX-12G T_DRAXX-4 T_DRAXX-5 T_DRAXX-6	DRAX41 / DRAX42	M	KINO41	J
Killingholme (case2: KILL – 450MW)	T_KILLPG-2	KILL40	M	KINO41	J

Table 10: Participants' operation over 630 SSPs

	Generation Capacity	Total QM	Average QM	Average Power
	MW	MWh	MWh	MW
Killingholme	450	83,234	132	264
Draxx	3,945	931,395	1,478.5	2,957

In some cases participants responding to signals can influence the Adjusted Seasonal Average Zonal TLFs notably.

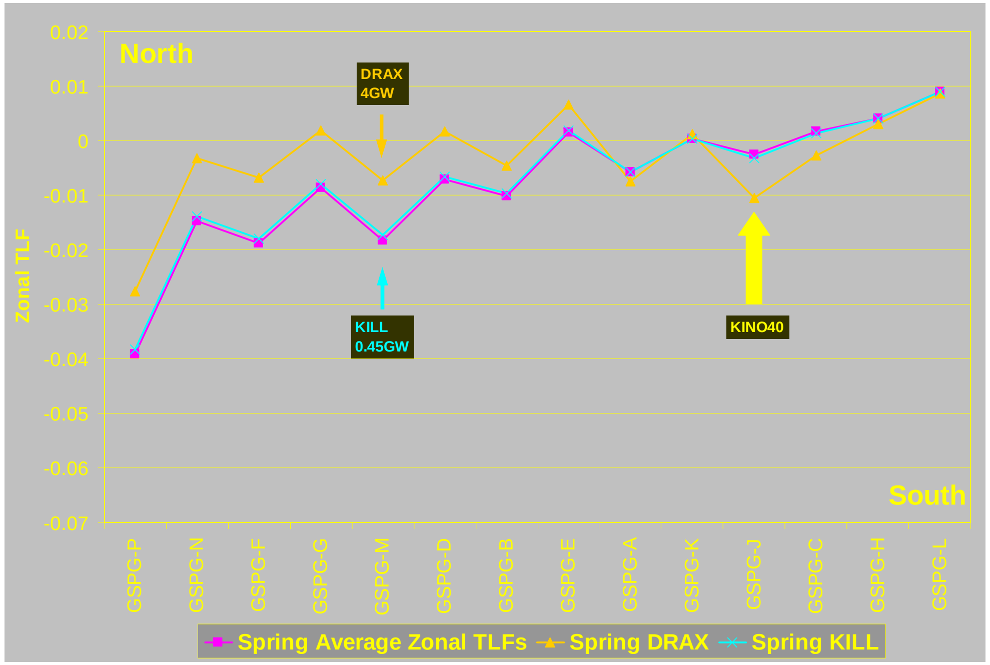

Figure 39: Adjusted Seasonal Average Zonal TLFs for the two cases of participants responding to signals compared with the baseline Adjusted Seasonal Average Zonal TLFs - Spring

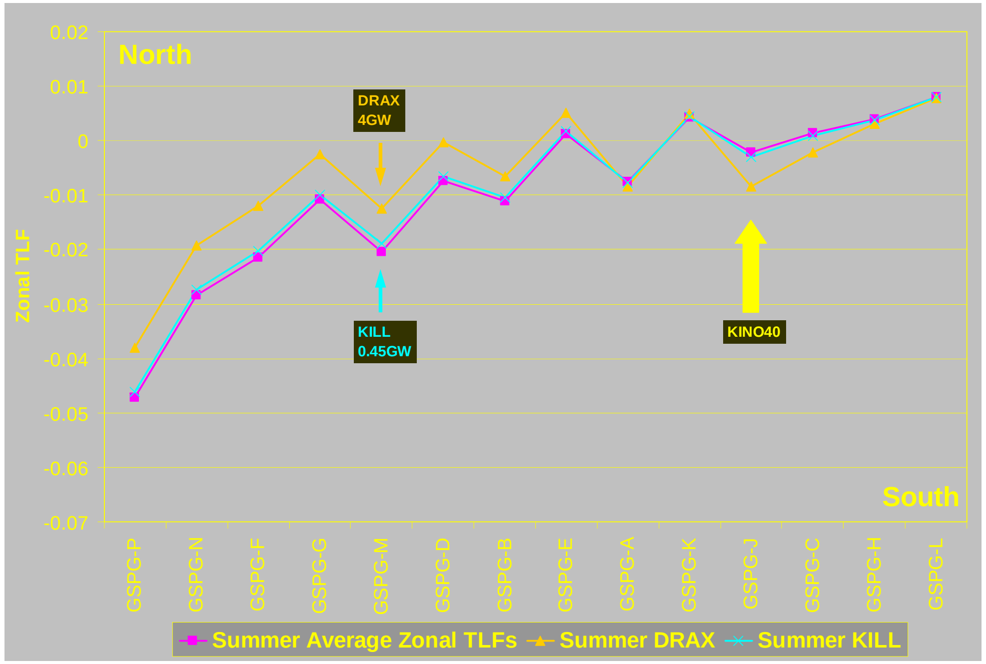

Figure 40: Adjusted Seasonal Average Zonal TLFs for the two cases of participants responding to signals compared with the baseline Adjusted Seasonal Average Zonal TLFs - Summer

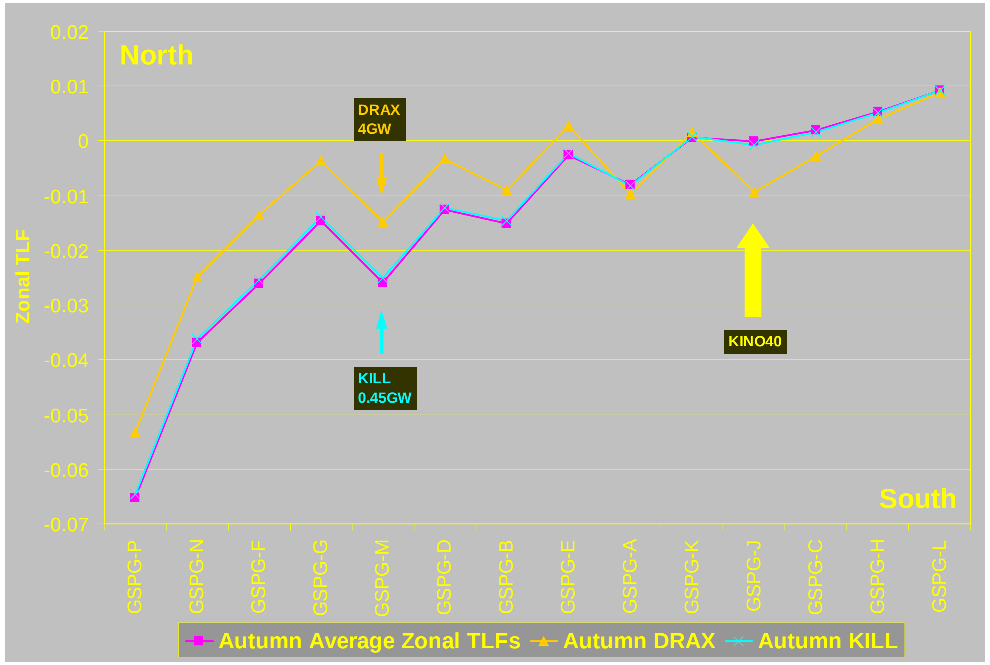

Figure 41: Adjusted Seasonal Average Zonal TLFs for the two cases of participants responding to signals compared with the baseline Adjusted Seasonal Average Zonal TLFs - Autumn

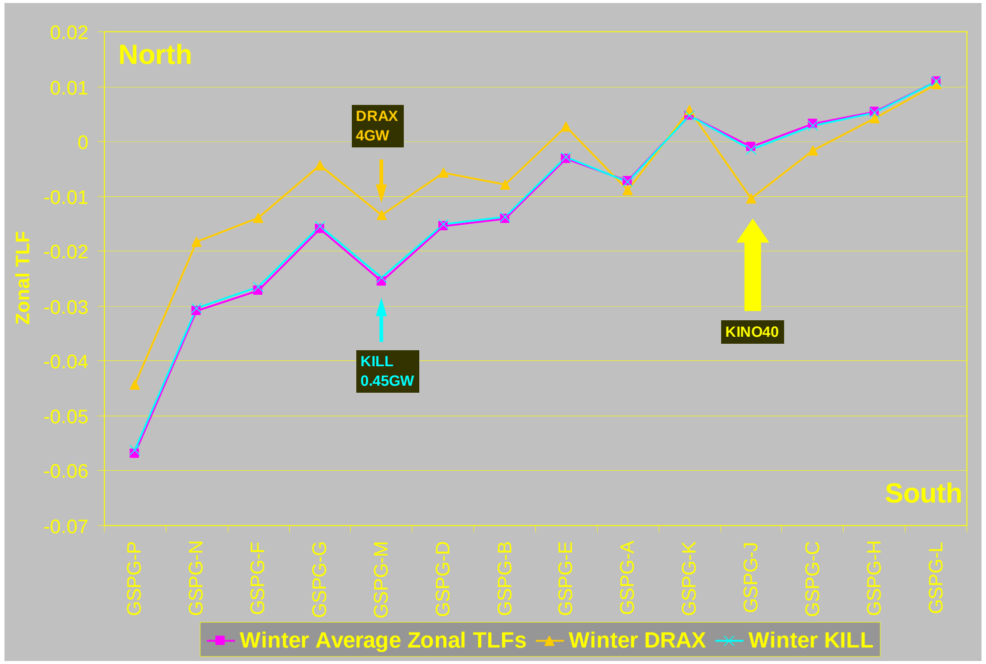

Figure 42: Adjusted Seasonal Average Zonal TLFs for the two cases of participants responding to signals compared with the baseline Adjusted Seasonal Average Zonal TLFs - Winter

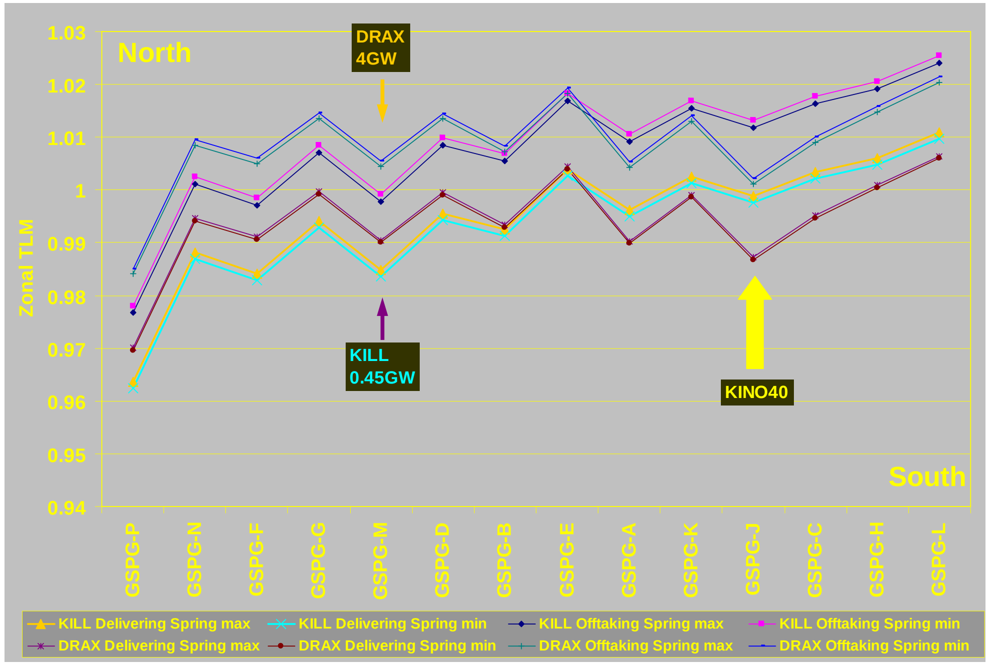

Figure 43: Delivering and Off-taking Zonal TLMs for the seasonal peak SP and seasonal trough SP, for the two cases of participants responding to signals - Spring

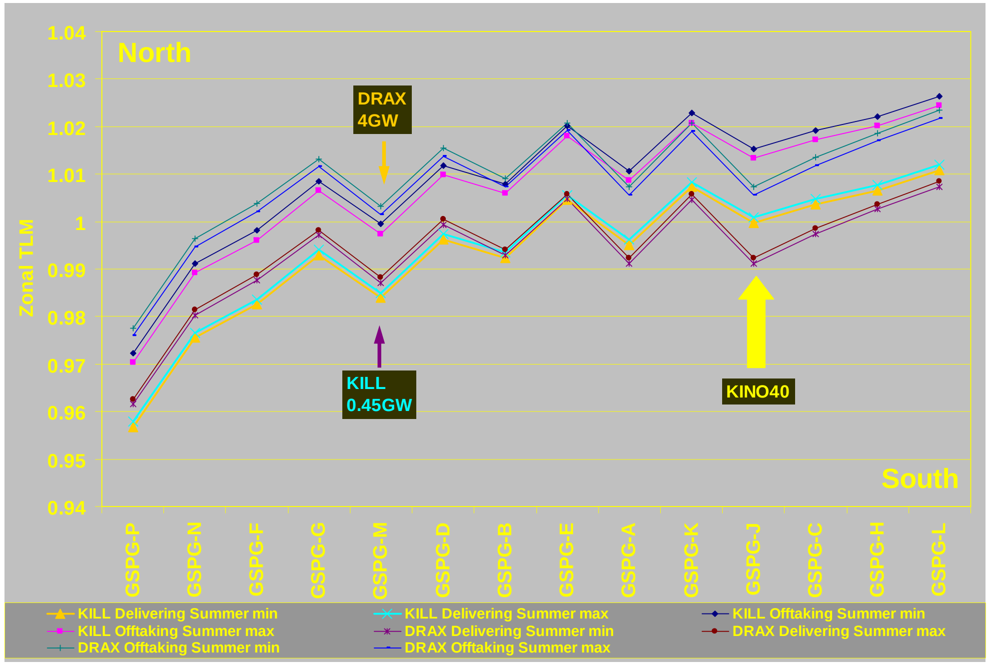

Figure 44: Delivering and Off-taking Zonal TLMs for the seasonal peak SP and seasonal trough SP, for the two cases of participants responding to signals - Summer

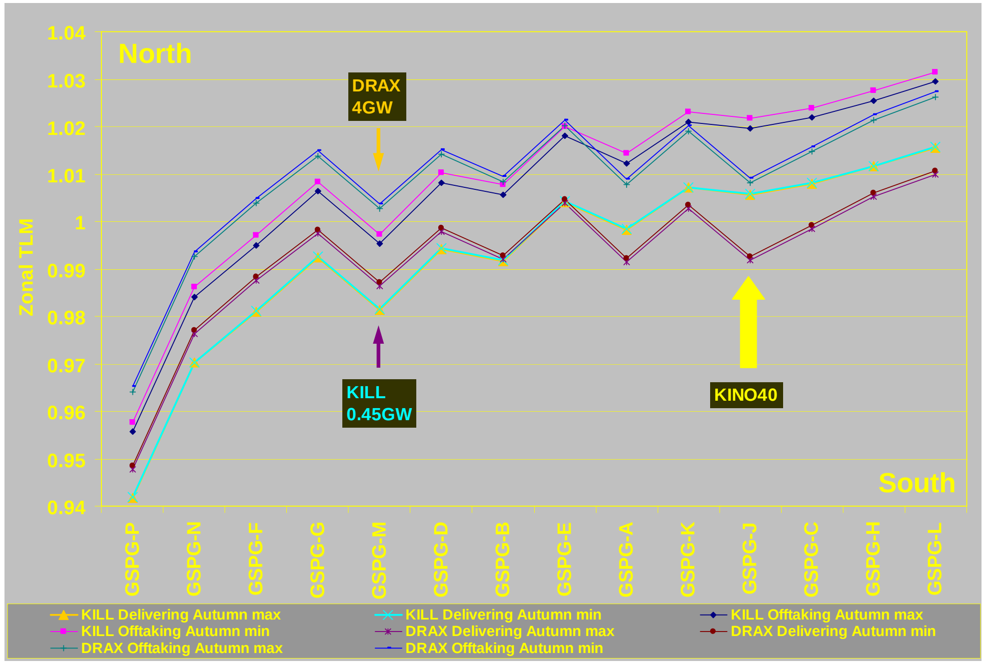

Figure 45: Delivering and Off-taking Zonal TLMs for the seasonal peak SP and seasonal trough SP, for the two cases of participants responding to signals - Autumn

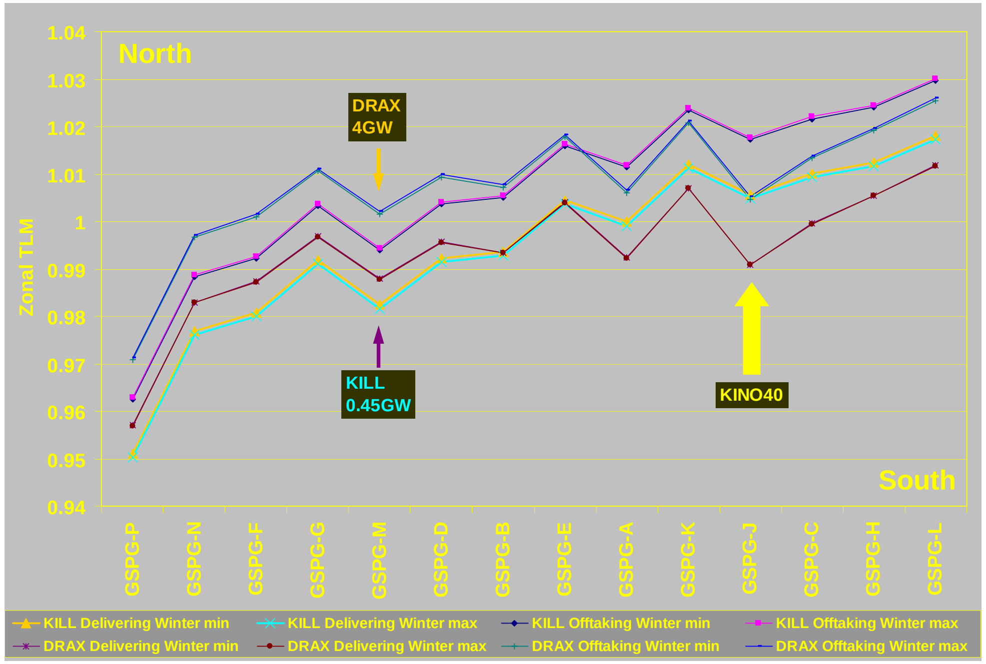

Figure 46: Delivering and Off-taking Zonal TLMs for the seasonal peak SP and seasonal trough SP, for the two cases of participants responding to signals - Winter

5.7 Task 6: Investigate the extent of generation relocation produces on reduction in overall heating losses

Task 6 considers the effect of participants responding to signals on the overall system heating losses. The cases examined are the two cases set in Task 5 and described in Section 5.6 (summarised in **Table 9** and in **Table 10**).

The heating losses considered in this task are those calculated by the load flow modelling process. It should be noted that such calculated losses differ from the Metered Volume Losses. This is due to ***(i)*** the model (which initially ignored 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 5 and Task 6 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 Seasonal Average Zonal TLFs and on the overall heating losses is obvious. With regard to the baseline overall heating losses, Killingholme case hardly change the overall heating losses, particularly as the volumes relocated are relatively small. Drax case reduces the overall heating losses significantly (**Table 11**).

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

Table 11: Reduction in system heating losses for the two cases of participants responding to signals

Case	Spring	Summer	Autumn	Winter	Annual
	Losses				
	MWh				
Baseline Case	**31,590.40**	**28,305.97**	**36,149.80**	**40,659.05**	**136,705.21**
DRAX (2GW from DRAX41/DRAX42 in GSP-M to KINO41 in GSP-J)	**29,510.66**	**25,265.66**	**31,116.28**	**35,705.42**	**121,598.01**
KILL (0.25GW from KILL40 in GSP-M to KINO41 in GSP-J)	**30,776.24**	**27,019.18**	**35,317.71**	**39,876.16**	**132,989.29**
	Percentage Difference				
DRAX	**-6.6%**	**-10.7%**	**-13.9%**	**-12.2%**	**-11.1%**
KILL	**-2.6%**	**-4.5%**	**-2.3%**	**-1.9%**	**-2.7%**

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

5.8 Task 7: 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 Volumes of a 1500 MW capacity generation 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 12**. 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 13**.

The results are presented in **Figure 47**, **Figure 48**, **Figure 49**, and **Figure 50** for spring, summer, autumn and winter respectively.

Table 12: Two plants chosen for the task

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

Table 13: Four indicative SSPs chosen for the task

Season	Sample Settlement Period
Spring	20080303-34
Summer	20080604-24
Autumn	20081126-38
Winter	20071219-33

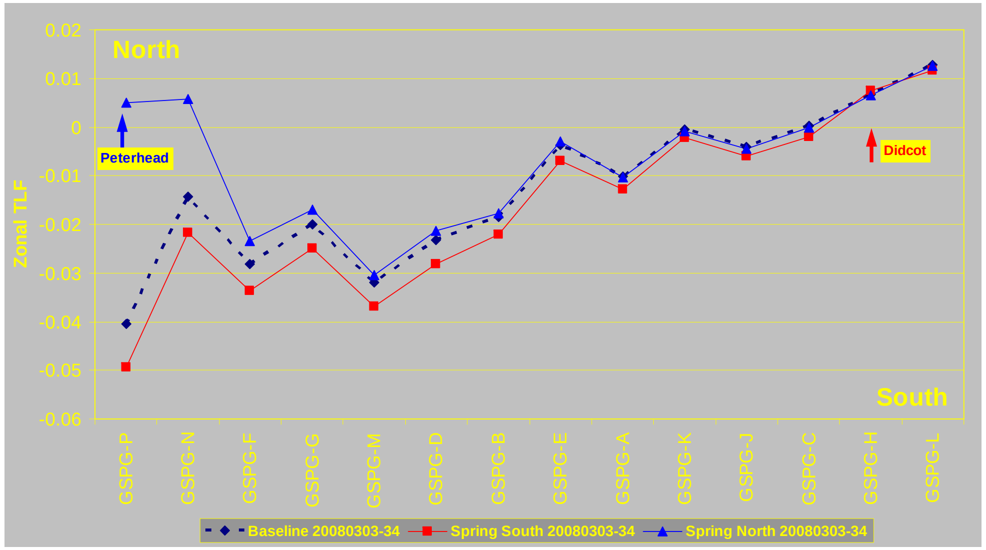

Figure 47: SSP Zonal TLFs for <u>spring</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

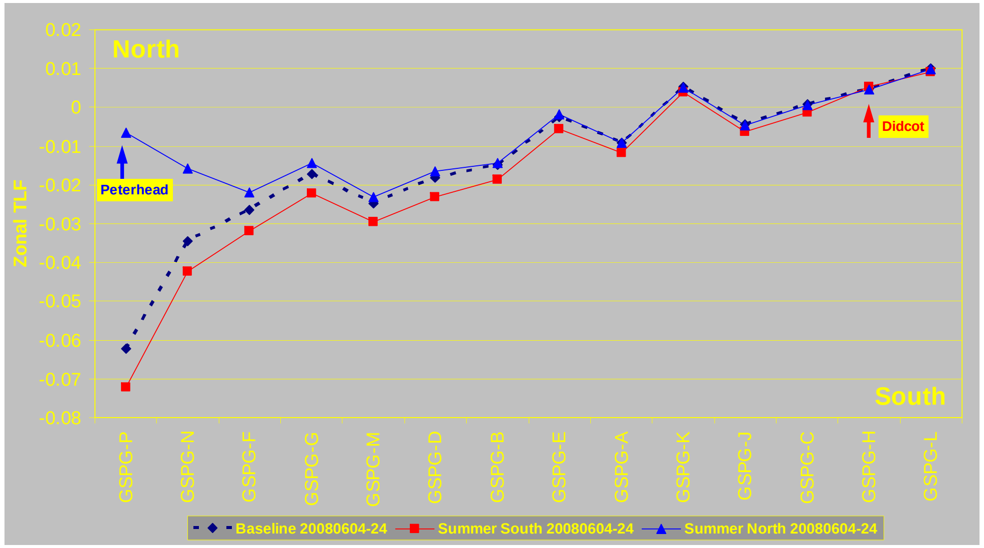

Figure 48: SSP Zonal TLFs for <u>summer</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

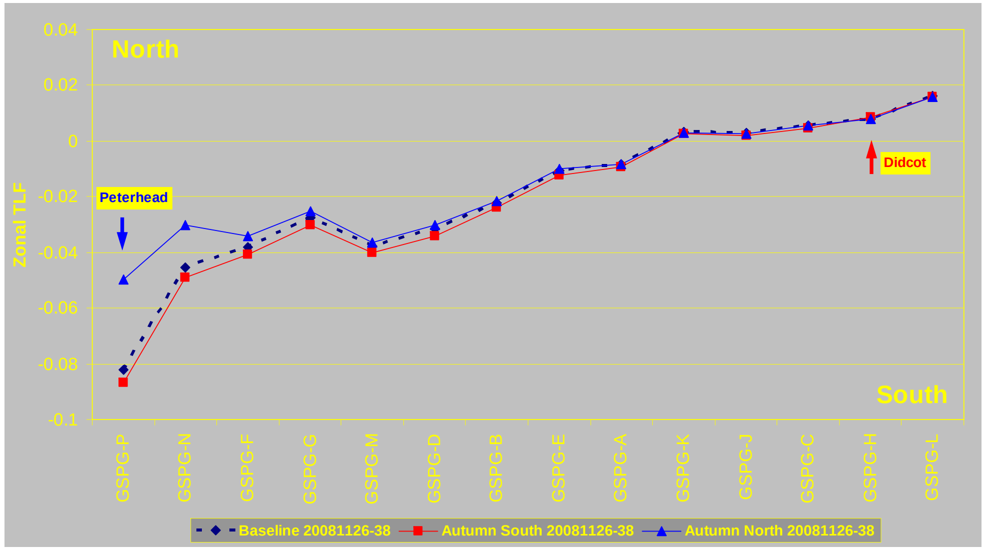

Figure 49: SSP Zonal TLFs for <u>autumn</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

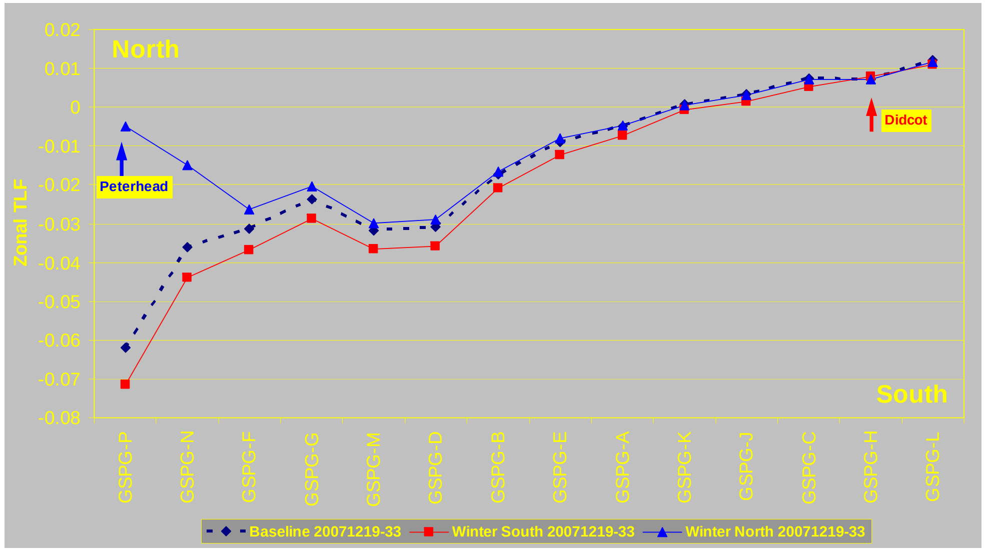

Figure 50: SSP Zonal TLFs for <u>winter</u> cases of plant breakdown or withdrawal against the baseline Adjusted SSP Zonal TLFs for the same SSP

Through all seasons the plant breakdown/withdrawal in the south has an effect of changing the Adjusted SSP Zonal TLFs in direction of decreasing the values (for example, negative values become more negative). The effect increases in magnitude gradually through the zones from south to north. However, the effect in the south is relatively modest and only increases tangibly in the north.

Through all seasons the plant breakdown/withdrawal in the north has an effect of changing the Adjusted SSP Zonal TLFs in direction of increasing the values (for example, negative values become less negative). The effect increases in magnitude gradually through the zones from south to north. However, while the effect in the south is relatively modest it becomes significant in the north.

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

5.9 Task 8: Modelling of intermittent generation

In modelling the effects of introducing a significant intermittent generation the following steps were applied:

- The delivering pattern (in terms of ½ h metered volumes) across the 630 sample Settlement Periods of an existing wind farm (≈125MW capacity) was taken;
- This delivering pattern was scaled proportionally to generate estimated metered volumes for a 2000MW capacity wind farm across the 630 sample Settlement Periods;
- These estimated metered volumes were then introduced at one of the two selected network nodes (see **Table 14**) at the time. The output metered volumes of other generators was scaled down proportionally, in total by the amount equal to the output of the new wind farm in each sample Settlement Period.

Table 14: Two cases of introducing a significant intermittent generation

Case Location	Node	Zone
Peterhead (North)	PEHE2U	GSPG-P (North of Scotland)
Grain (South)	GRAI40	GSPG-J (SEEBOARD)

For each of the two locations selected (see **Table 14**) Adjusted Seasonal Average Zonal TLFs were calculated separately. These results are presented jointly and against that Base Adjusted Seasonal Average Zonal TLFs (from Task 1) in **Figure 51**, **Figure 52**, **Figure 53**, and **Figure 54** for spring, summer, autumn and winter respectively.
Increased intermittent generation in the north (Peterhead) would amplify negative values of local Zonal TLFs. The effect of the increased intermittent generation at Grain is too small to be obvious. The effect of increased intermittent generation tends to be of a relatively local character.

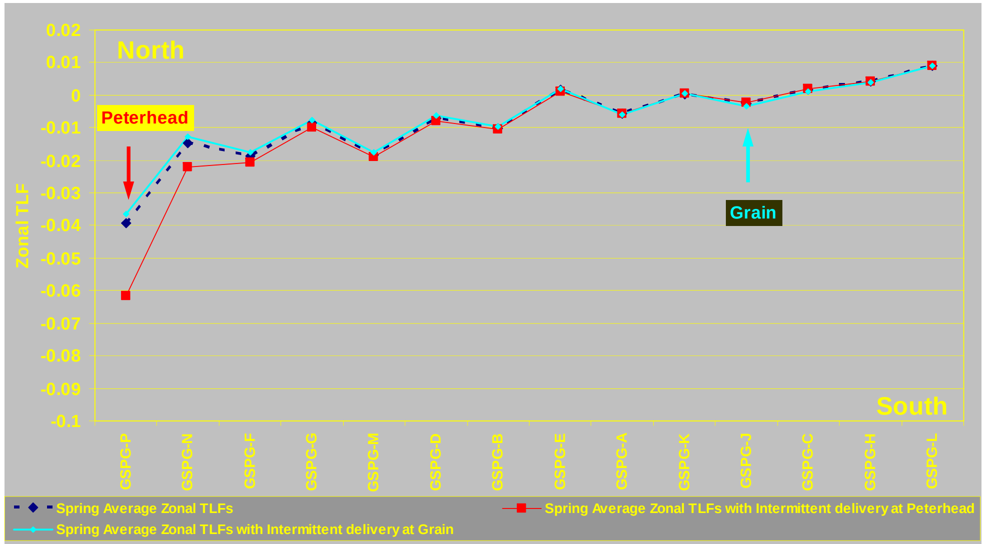

Figure 51: Adjusted Seasonal Average Zonal TLFs for two cases of new intermittent generation locations - SPRING

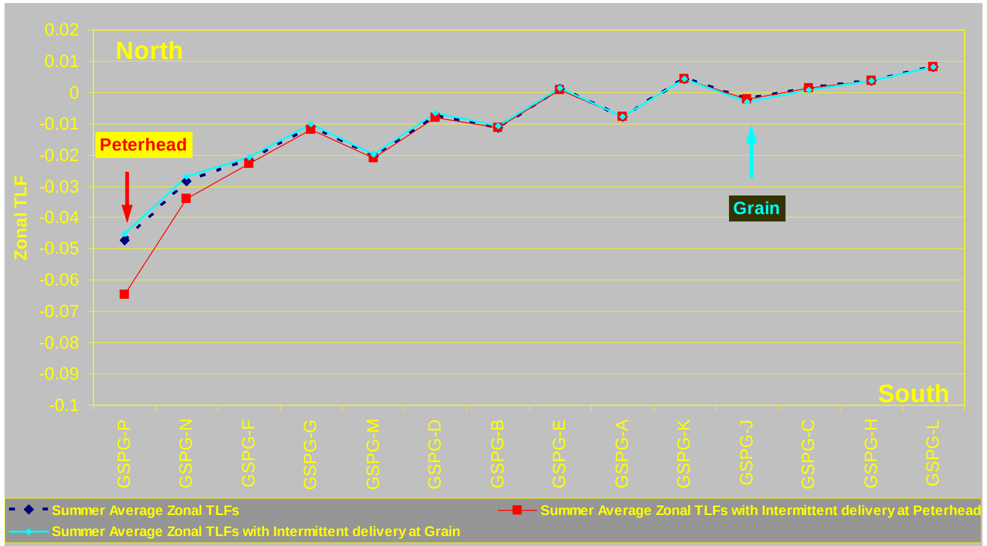

Figure 52: Adjusted Seasonal Average Zonal TLFs for two cases of new intermittent generation locations - SUMMER

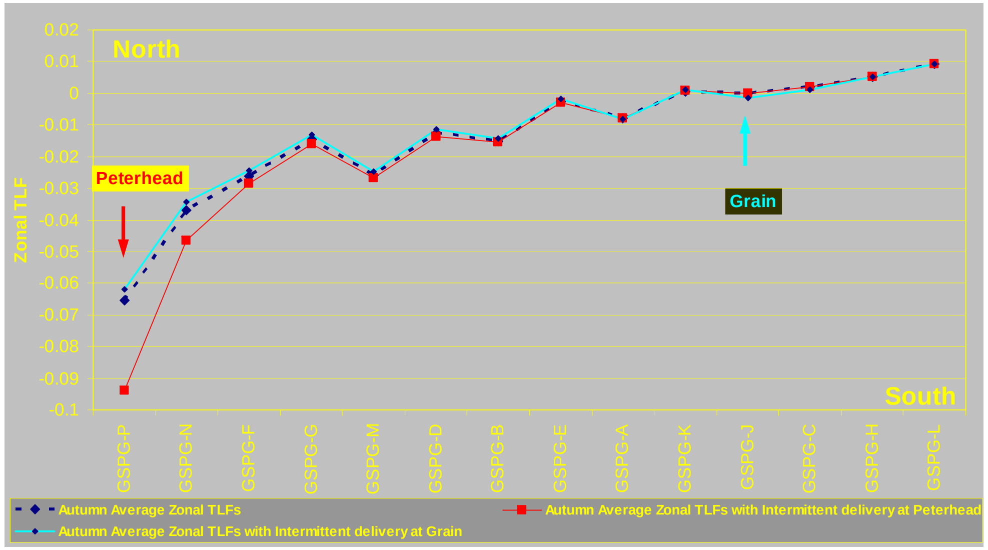

Figure 53: Adjusted Seasonal Average Zonal TLFs for two cases of new intermittent generation locations - AUTUMN

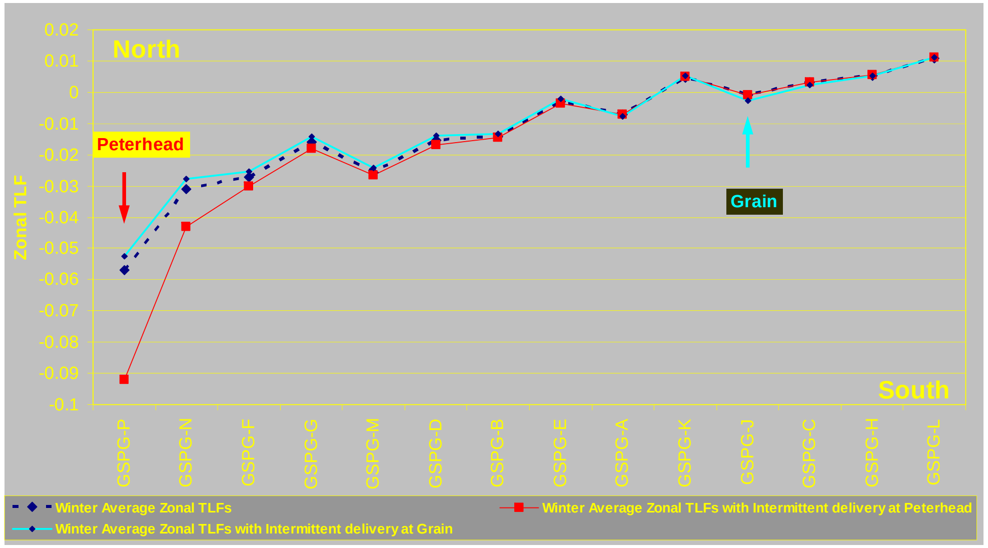

Figure 54: Adjusted Seasonal Average Zonal TLFs for two cases of new intermittent generation locations - WINTER

The effect of increased intermittent generation tends to be of a local character.

Figure 55, **Figure 56**, **Figure 57**, and **Figure 58** present Seasonal Average of Delivering and Off-taking Zonal TLMs for the two cases of this Task 8 against the Seasonal average of Base Delivering and Off-taking Zonal TLMs for spring, summer, autumn and winter respectively

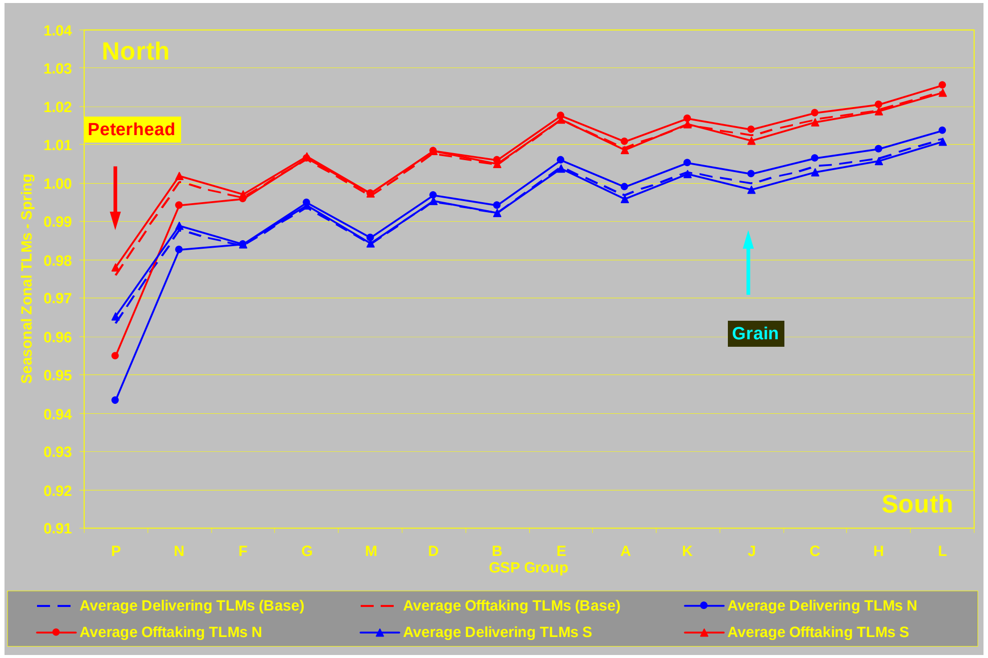

Figure 55: Seasonal Average of Delivering and Off-taking Zonal TLMs for the two cases of new significant intermittent generation against the base case – SPRING

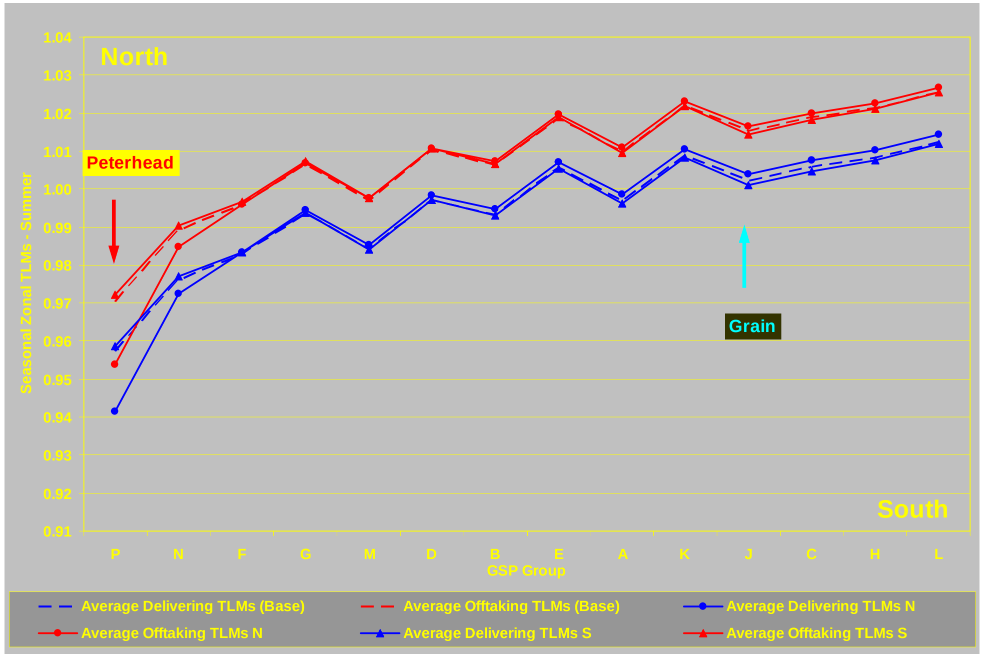

Figure 56: Seasonal Average of Delivering and Off-taking Zonal TLMs for the two cases of new significant intermittent generation against the base case – SUMMER

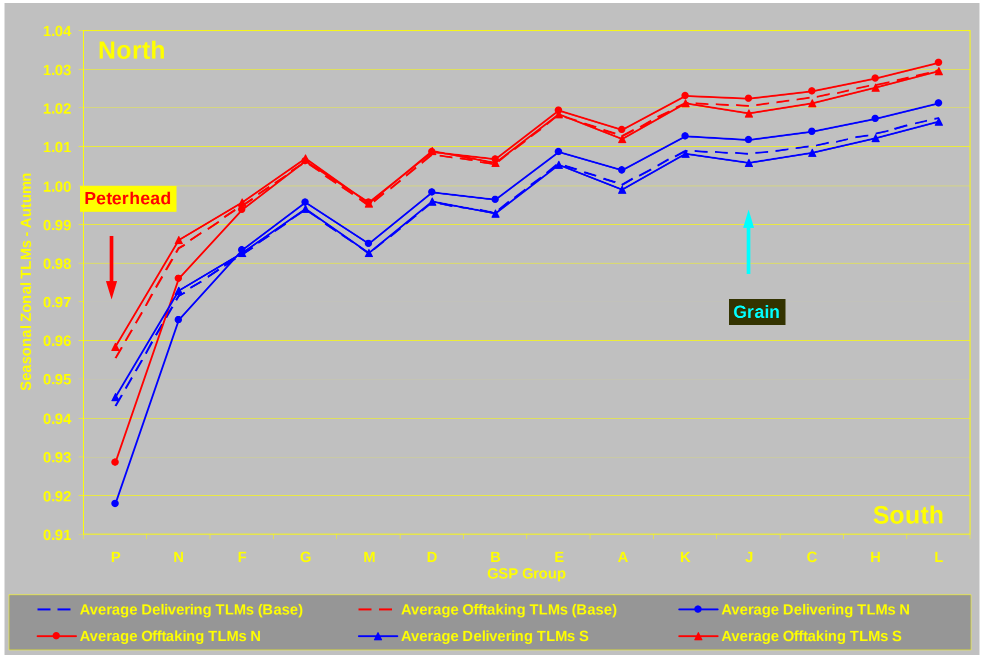

Figure 57: Seasonal Average of Delivering and Off-taking Zonal TLMs for the two cases of new significant intermittent generation against the base case – AUTUMN

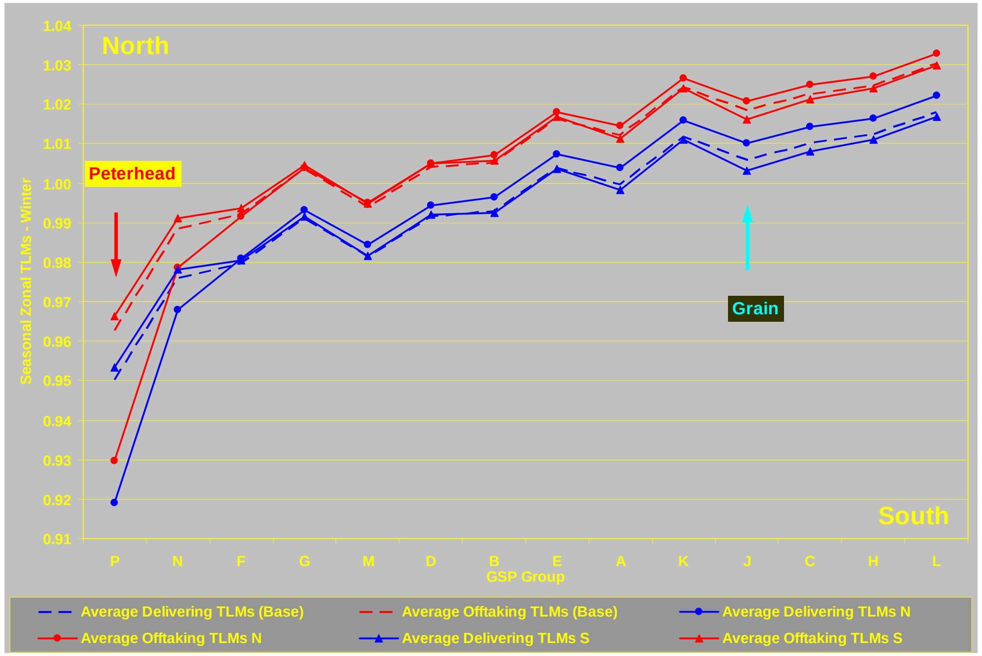

Figure 58: Seasonal Average of Delivering and Off-taking Zonal TLMs for the two cases of new significant intermittent generation against the base case – WINTER

5.10 Task 9: Examine impact of including Offshore Transmission Nodes

Currently any offshore transmission nodes are not part of the Transmission System and not the responsibility of National Grid, and thus not included in the Task 1 (and other Tasks) modelling. As there is a proposal to include these offshore transmission nodes into the Transmission System this task was set to examine the impact on TLFs of such a new regime.

This task is intended to consider the present offshore transmission nodes. However, because only a very few existing nodes would become offshiore transmission nodes there was a need to include some additional offshore transmission nodes that are imminent in the very near future in an attempt to produce a more tangible impact and meaningful results.

Six offshore wind generation farms were identified for this Task 9 – one operational and 5 due in the near future (**Table 15**).

The delivering pattern (in terms of ½ h metered volumes) across the 630 sample Settlement Periods of an existing wind farm (≈125MW capacity) was used to produce the modelled Metered Volumes for the 5 new wind farms. For that purpose this delivering pattern was scaled proportionally in accordance with the installed capacity of the new wind farms.

Metered Volumes of the existing generators were decreased proportionally for the total of the Metered Volumes of the 5 new wind farms for each SSP.

The network used in this task was the intact network model from Task 1 adjusted, in consultation with P229 Modification Group, to include the offshore transmission nodes and branches.

Table 15: Six offshore wind farms for which their offshore transmission nodes and branches were included in the model

Offshore wind farm	Capacity [MW]	Onshore node	Offshore node	GSPG Zone
Ormonde	150	HEYS10	HEYS1S	G
Barrow	90	HEYS10	HEYS1F	G
Robin Rigg	180	HARK10	HARK1F	G
Gunfleet Sands 1 and 2	172	BRFO10	BRFO1F	A
Sheringham Shoal	315	NORW10	NORW1F	A
Greater Gabbard	504	SIZE10	SIZE1F	A

Figure 59, **Figure 60**, **Figure 61**, and **Figure 62** present the Adjusted Seasonal Average Zonal TLFs for the case of including the offshore transmission nodes against the baseline Seasonal Adjusted Average Zonal TLFs for spring, summer, autumn and winter respectively.

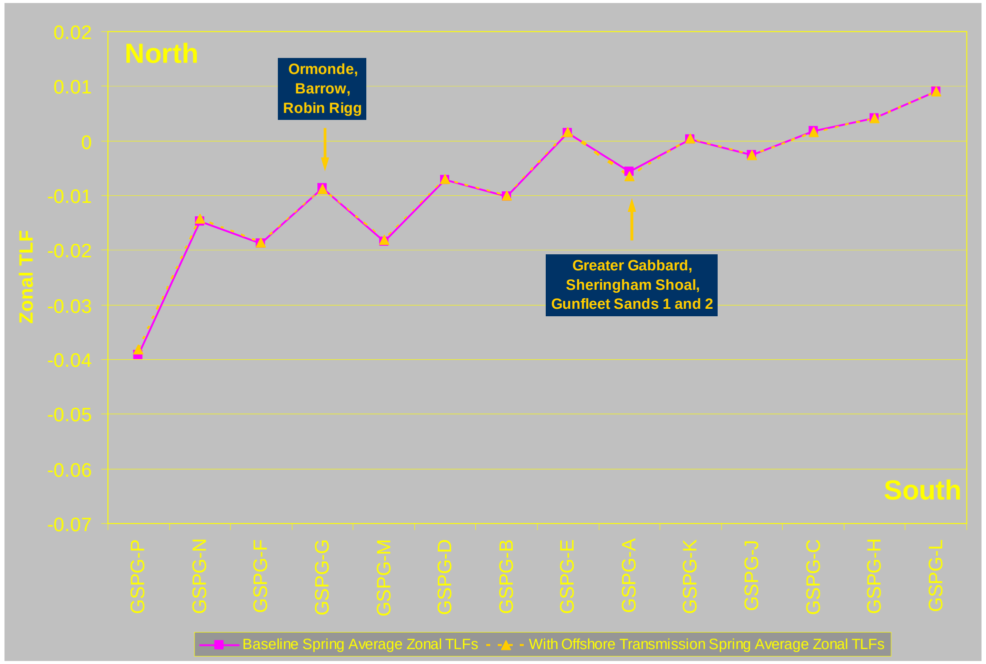

Figure 59: Seasonal Adjusted Average Zonal TLFs for the case of including the offshore transmission nodes against the baseline Seasonal Adjusted Average Zonal TLFs – SPRING

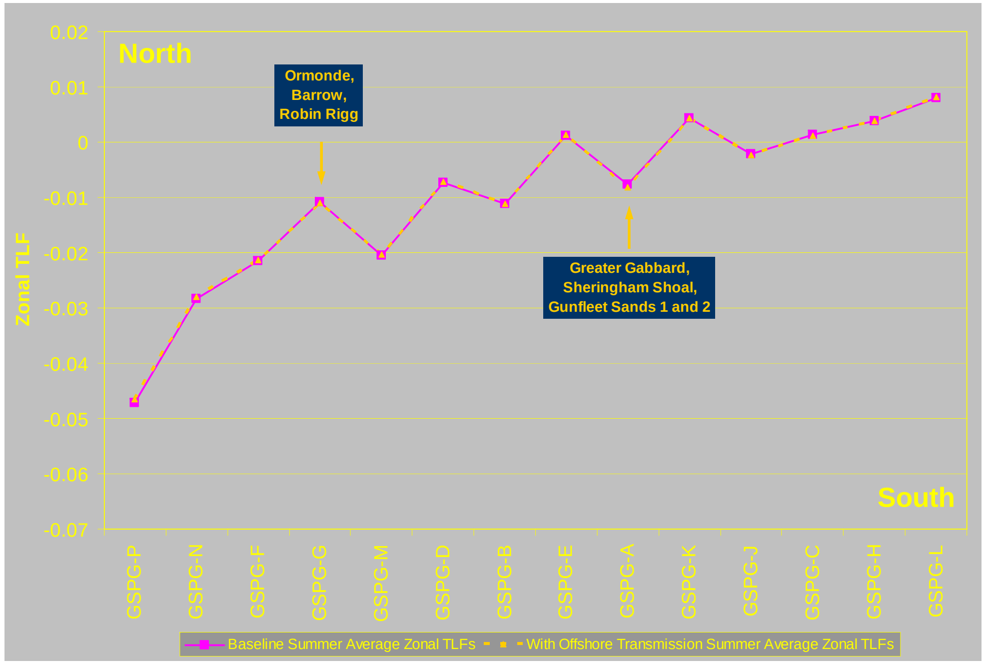

Figure 60: Seasonal Adjusted Average Zonal TLFs for the case of including the offshore transmission nodes against the baseline Seasonal Adjusted Average Zonal TLFs – SUMMER

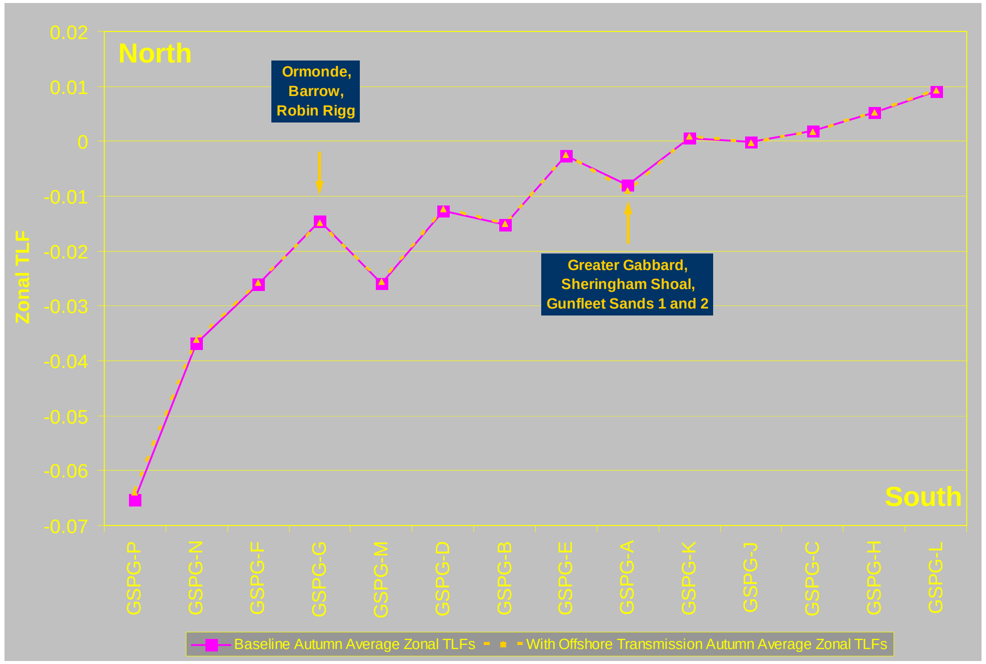

Figure 61: Seasonal Adjusted Average Zonal TLFs for the case of including the offshore transmission nodes against the baseline Seasonal Adjusted Average Zonal TLFs – AUTUMN

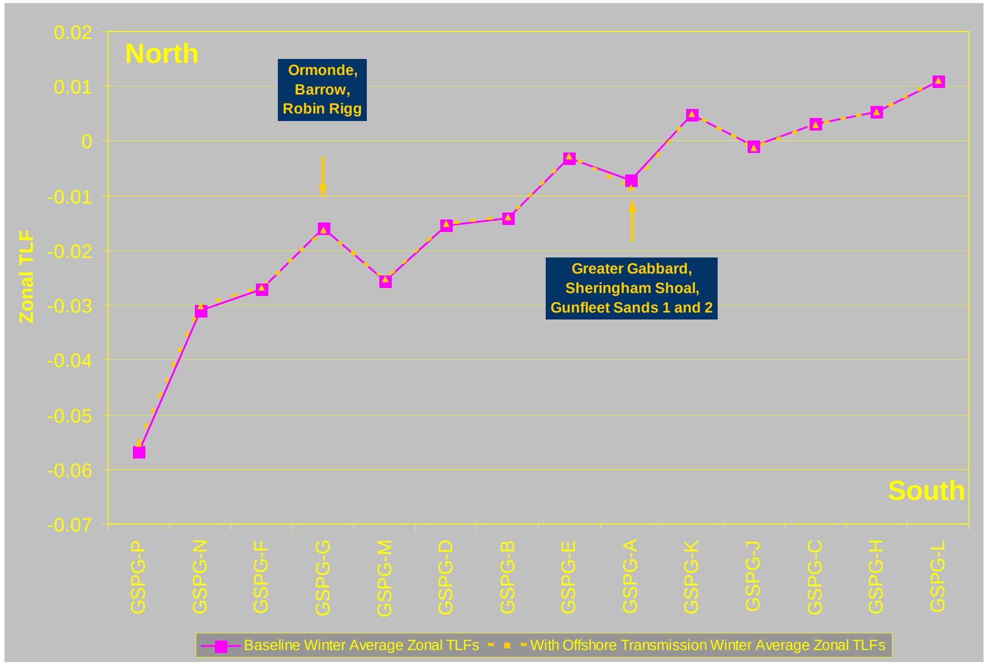

Figure 62: Seasonal Adjusted Average Zonal TLFs for the case of including the offshore transmission nodes against the baseline Seasonal Adjusted Average Zonal TLFs – WINTER

The effect of including present offshore transmission nodes is hardly noticeable.

5.11 Task 10: Impact of future developments

This Task 10 was designed to demonstrate sensitivity of TLFs to significant future developments, in particular to new large offshore wind farms, new interconnections to neighbouring countries and new offshore DC transmission lines. Task 10 was designed to combine all these influences in an attempt to reflect what is speculated to happen in about up to 10 years.

The network used was the intact network from Task 1 with minor adjustments.

Table 16: New large offshore wind farms modelled in Task 10 (in addition to those listed in Table 15)

Offshore wind farm	Capacity [MW]	Onshore node	GSPG Zone
Docking Shoal	500	WALP10	A
Race Bank	500	WALP10	A
Humber	300	SAEN10	M
Triton Knoll	600	SHBA40	M
	600	WALP40	A
Lincs	250	WALP10	A
Westermost Rough	240	SAEN10	M
Dudgeon East	300	NORW10	A
London Array	500	CANT40	J
	500	KEMS40	J
Thanet	300	CANT10	J
Walney 1	75	HEYS10	G
	75	STAH10	G
Walney 2	300	STAH10	G
Gwynt y Mor	450	PENT40	D
	300	DEES41	D
West Duddon	250	HEYS10	G
	250	STAH10	G

Offshore wind farm	Capacity [MW]	Onshore node	GSPG Zone
Alverdiscott	750	ALVE4A	L
	750	ALVE4B	L
Norfolk	1833.3	NORW40	A
	1833.3	SIZE40	A
	1833.3	RAYL40	A
Beachy Head	1000	LOVE40	H
Dogger Bank	1200	CREB40	M
	1200	KEAD41	M
	1200	KEAD42	M
	1200	KILL40	M
	1200	GRIW40	M
Hornsea	800	CREB40	M
	800	KEAD41	M
	800	KEAD42	M
	800	KILL40	M
	800	GRIW40	M
Firth of Forth	7000	TORN40	N
Shetland	600	DOUN20	P

In addition to the offshore wind farms listed in **Table 15** this Task 10 also included and modelled wind farms listed in **Table 16**.

The delivering pattern (in terms of ½ h metered volumes) across the 630 sample Settlement Periods of an existing wind farm (≈125MW capacity) was used to produce the modelled Metered Volumes for all the planned wind farms. For that purpose this delivering pattern was scaled proportionally in accordance with the intended installed capacity of the new wind farms.

Task 10 included three new interconnections as listed in **Table 17**. It was not possible to predict the utilisation pattern of these new interconnections, thus the delivering/off-taking patterns of existing interconnections were used in modelling the new interconnections. Metered Volumes for UK-Belgium and UK-Netherland interconnections follow the pattern of the existing French interconnection and Metered Volumes for UK-RoI interconnection follow the pattern of the existing Moyle interconnection (scaling proportional to the intended installed capacity was applied for each).

Two DC offshore transmission lines (listed in **Table 18**) were modelled as pairs of off-taking and delivering nodes. Losses were accounted for when the off-taking and delivering volumes were modelled. It was not possible to predict how these two offshore DC lines would be utilised. Therefore, a simplified utilisation pattern was applied. DC transmission lines were loaded 100%, 75% and 50% during Winter, Spring/Autumn and Summer respectively (1/2 of that during night SSPs).

Table 17: New interconnections included in Task 10 modelling

Interconnection	Export Capacity [MW]	Import Capacity [MW]	Bus Name	GSPG Zone
UK - Netherland	1270	1200	GRAI40	J
East-West (UK - RoI)	500	500	DEES42	D
Nemo (UK - Belgium)	1320	1320	CANT40	J

Table 18: New offshore DC lines included in Task 10 modelling

DC Offshore transmission line	Assumed Capacity [MW]	Bus 1		Bus 2		Length [km]
		Name	GSPG Zone	Name	GSPG Zone	
Peterhead - Hawthorn	1500	PEHE21	P	HAWP4A	F	370
Hunterston - Deeside	1500	HUER40	N	DEES42	D	420

There was a tangible increase in the total of Delivering Metered Volumes due to the new offshore generation introduced and the net effect of the new interconnections.

Offtaking Metered Volumes were increased to represent load demand growth effects (1% year on year)

After accounting for the estimated system losses (including the losses on the DC offshore transmission lines) the existing Delivering Metered Volumes (existing generation) were proportionally decreased.

Figure 63, **Figure 64**, **Figure 65**, and **Figure 66** present the impact of modelled new large offshore wind farms, new interconnections to neighbouring countries and new offshore DC transmission lines on the Adjusted Seasonal Average Zonal TLFs as compared to Baseline Adjusted Seasonal Average Zonal TLFs for spring, summer, autumn and winter respectively.

In **Figure 63**, **Figure 64**, **Figure 65**, and **Figure 66** a large impact can be observed in the north and a tangible impact can be observed close to the continental interconnections. The large impact in the north could be attributed to offshore DC transmission lines as well as, to an extent, to partial replacement effect of new generation for the existing generation. Similarly, the lack of tangible effect in GSPG-M (Yorkshire Electricity) could be explained as due to the replacement effect of new generation for the existing generation – GSPG-M is the largest delivering zone (almost twice larger than the second largest) and the proportional reduction in Metered Volumes of the existing generation was the highest in this zone.

Delivering pattern of the offshore wind farms was based on an onshore wind farm as there were no suitable offshore wind farms available for this purpose. Offshore wind farms tend to have a better utilisation than onshore wind farms. In that respect their influence would be somewhat greater than modelled. Still, it is believed that the overall speculative effects of such significant future development as that modelled are, in broad terms, picked up correctly in this task.

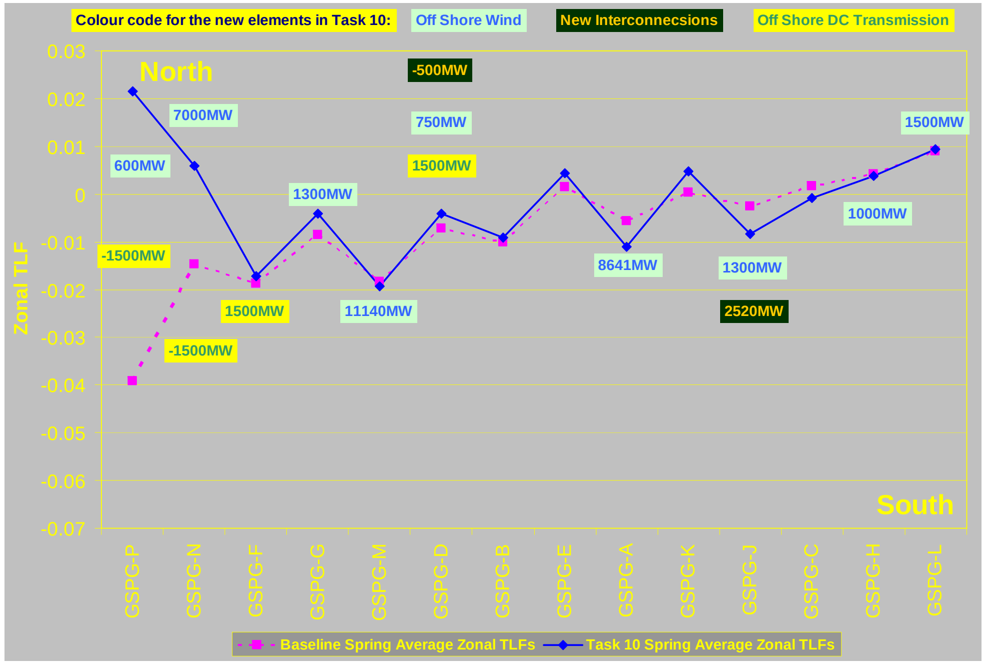

Figure 63: Seasonal Adjusted Average Zonal TLFs for the case of including the new large offshore delivery, interconnections and offshore DC transmission against the baseline Seasonal Adjusted Average Zonal TLFs – SPRING

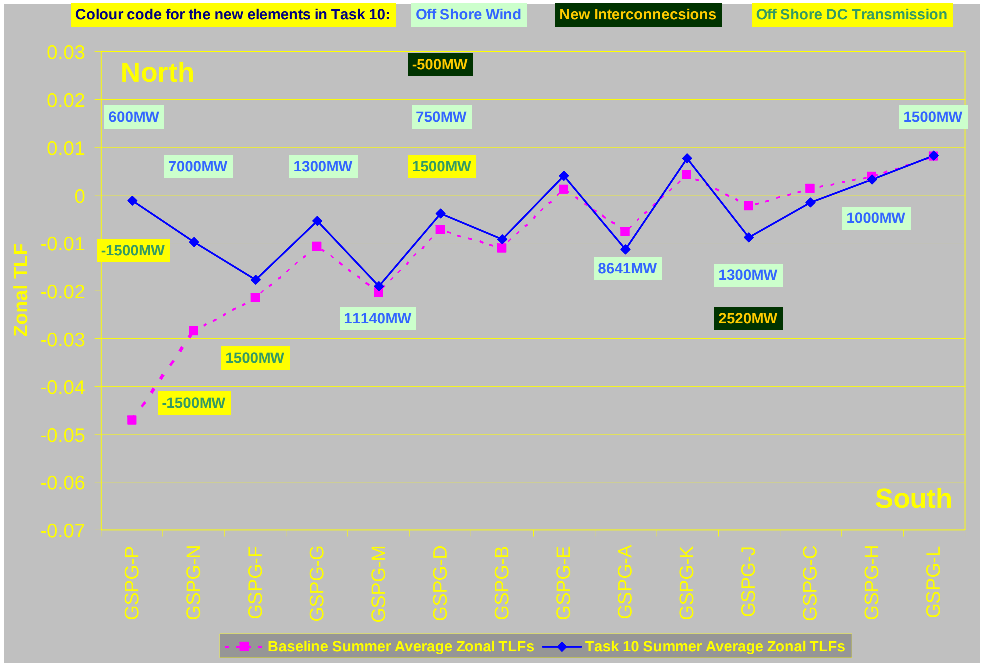

Figure 64: Seasonal Adjusted Average Zonal TLFs for the case of including the new large offshore delivery, interconnections and offshore DC transmission against the baseline Seasonal Adjusted Average Zonal TLFs – SUMMER

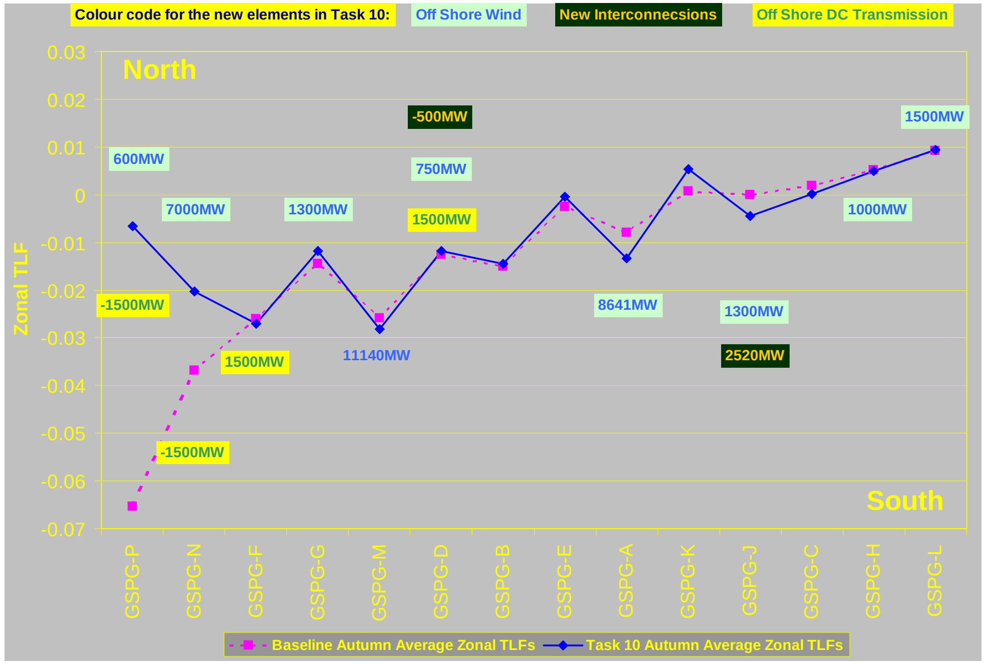

Figure 65: Seasonal Adjusted Average Zonal TLFs for the case of including the new large offshore delivery, interconnections and offshore DC transmission against the baseline Seasonal Adjusted Average Zonal TLFs – AUTUMN

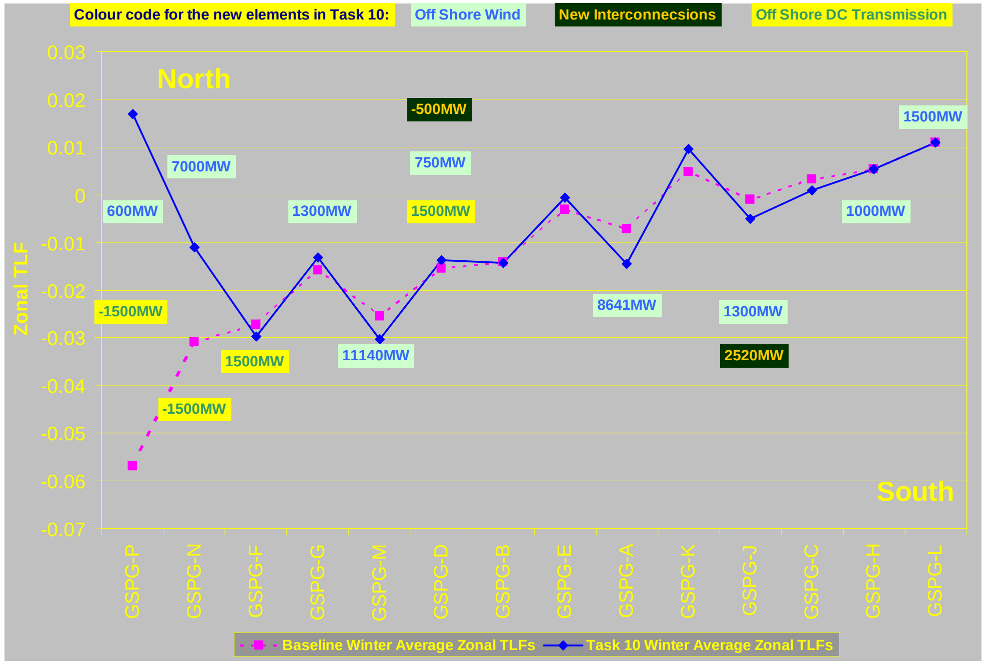

Figure 66: Seasonal Adjusted Average Zonal TLFs for the case of including the new large offshore delivery, interconnections and offshore DC transmission against the baseline Seasonal Adjusted Average Zonal TLFs – WINTER

Potentially there could be a large impact on TLFs from new offshore wind farms, interconnectors and offshore DC lines.

Figure 67, **Figure 68**, **Figure 69**, and **Figure 70** present Seasonal Delivering and Off-Taking Minimal, Maximal, and Average TLMs for Task 10 modelled conditions for spring, summer, autumn and winter respectively.

Figure 71, **Figure 72**, **Figure 73**, and **Figure 74** present Seasonal Delivering and Off-Taking Average TLMs for Task 10 modelled conditions as compared to the Base Seasonal Delivering and Off-Taking Average TLMs (from Task 1)

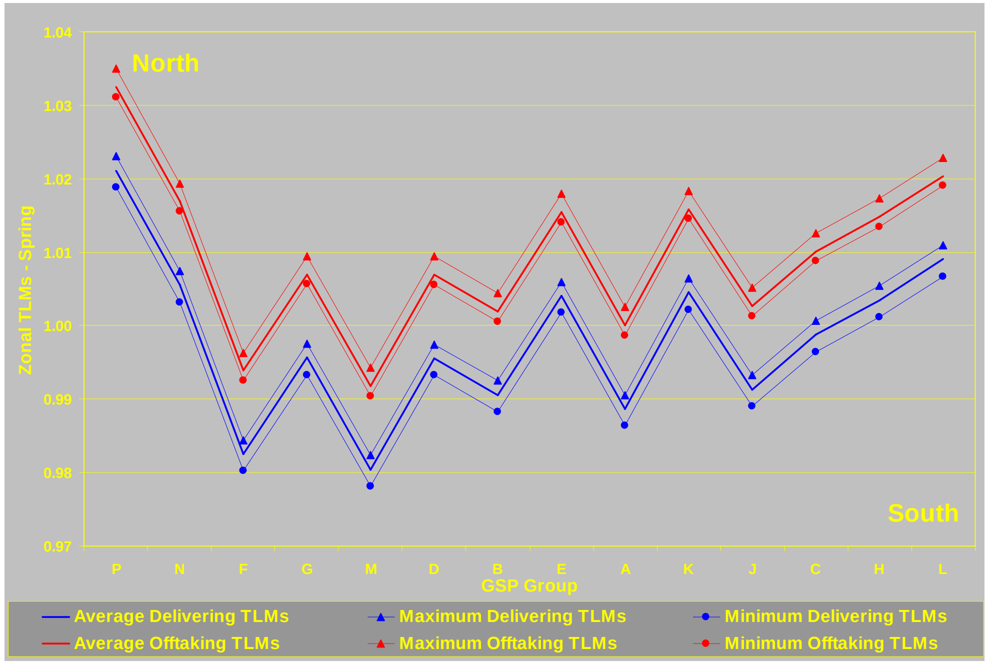

Figure 67: Seasonal Delivering and Off-Taking Minimal, Maximal and Average TLMs for Task 10 – SPRING

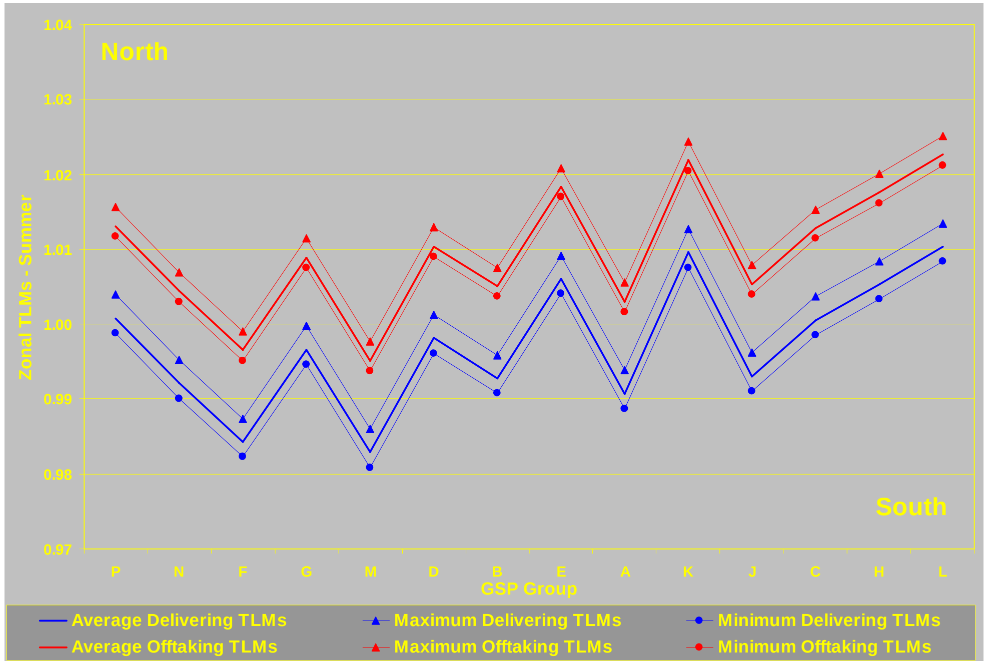

Figure 68: Seasonal Delivering and Off-Taking Minimal, Maximal and Average TLMs for Task 10 – SUMMER

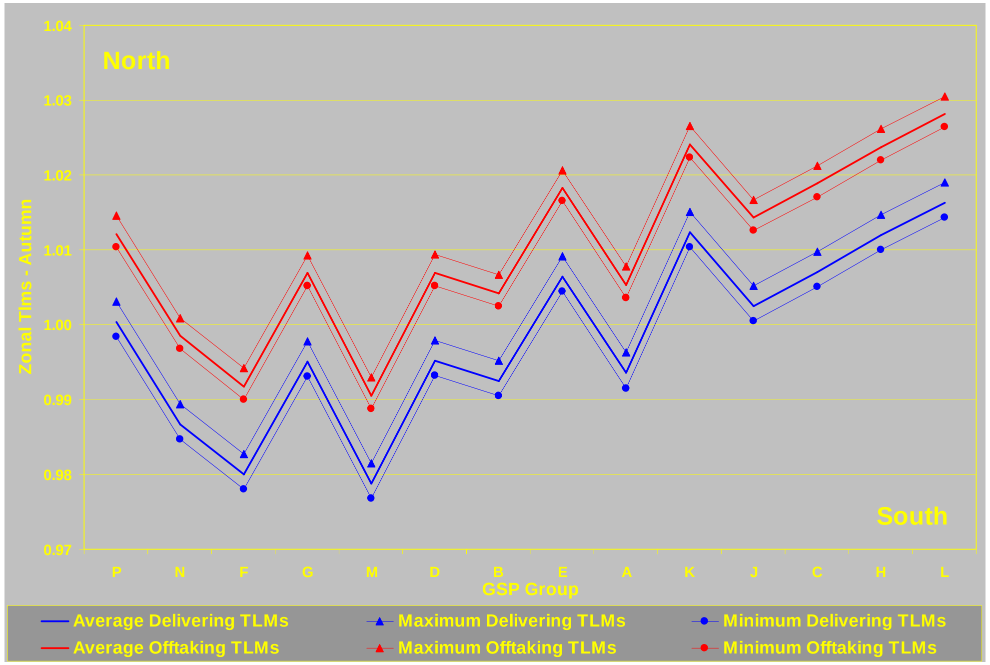

Figure 69: Seasonal Delivering and Off-Taking Minimal, Maximal and Average TLMs for Task 10 – AUTUMN

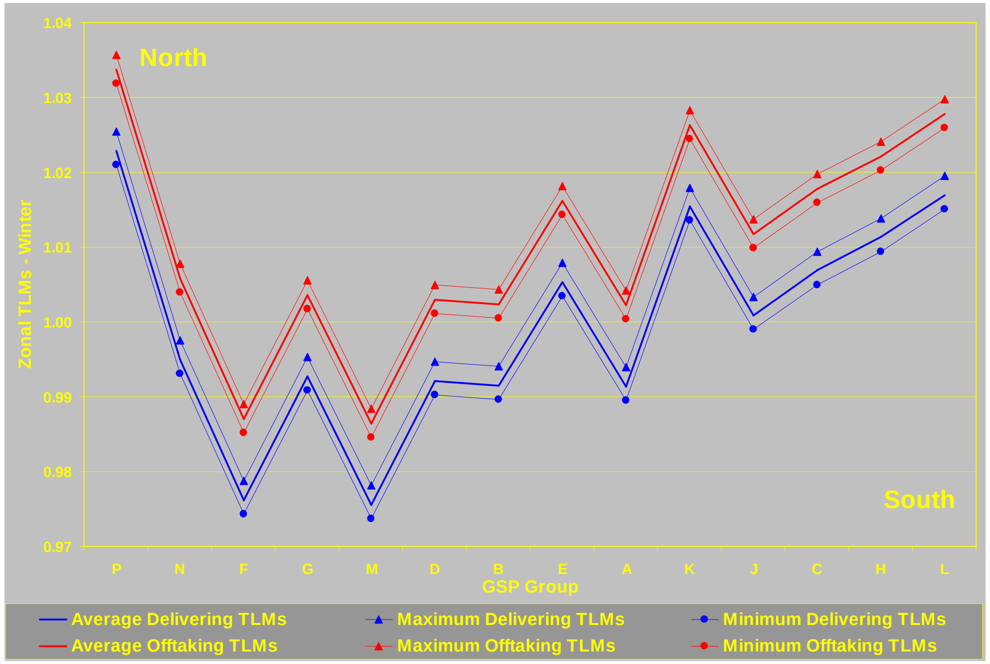

Figure 70: Seasonal Delivering and Off-Taking Minimal, Maximal and Average TLMs for Task 10 – WINTER

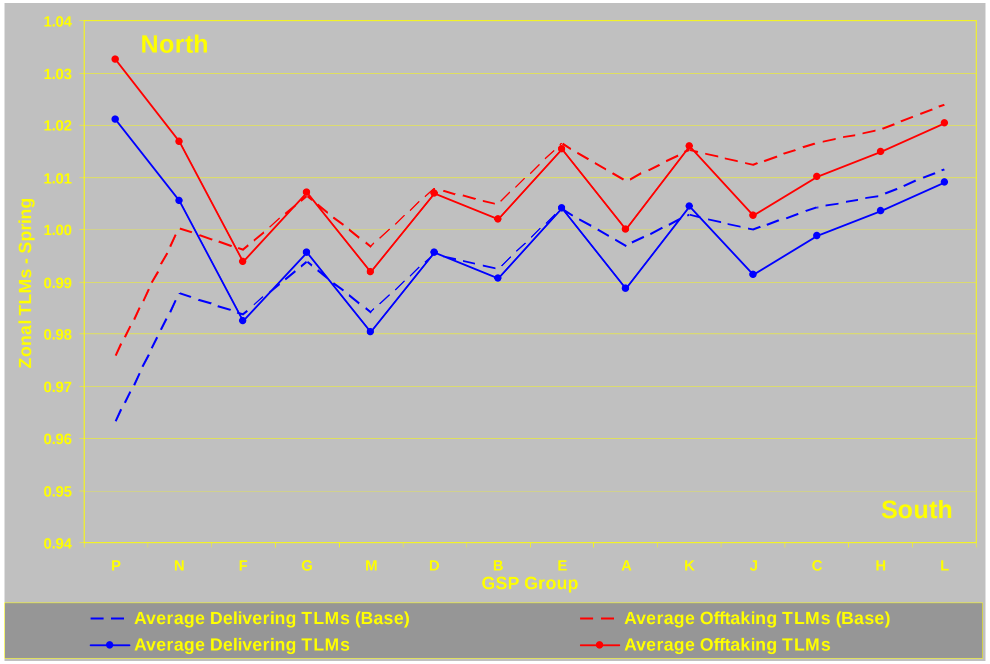

Figure 71: Seasonal Delivering and Off-Taking Average TLMs for Task 10 as compared to Base Seasonal Delivering and Off-Taking Average TLMs (from Task 1) – SPRING

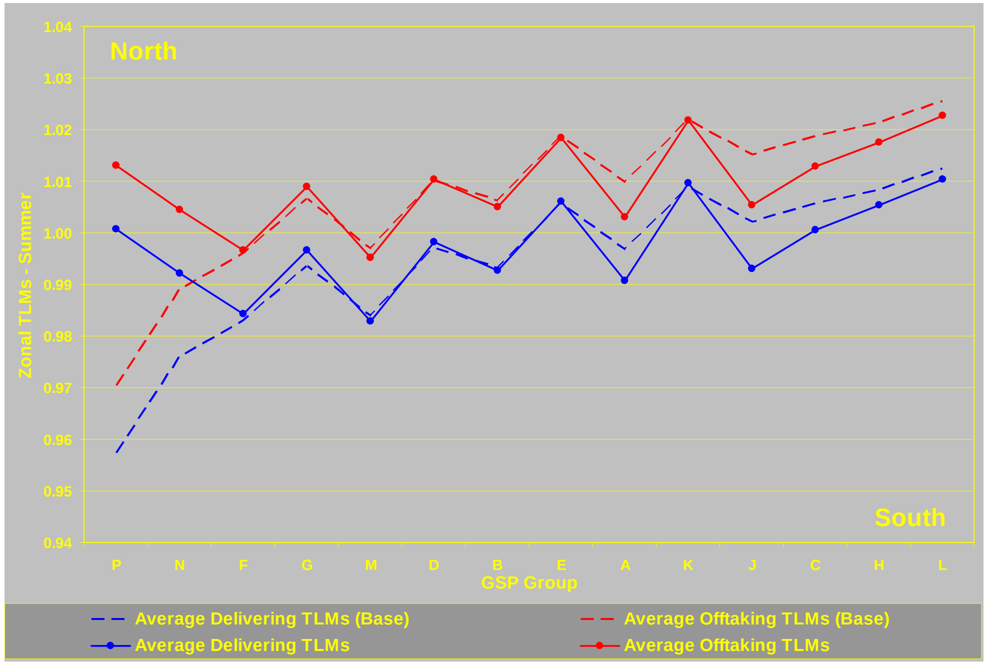

Figure 72: Seasonal Delivering and Off-Taking Average TLMs for Task 10 as compared to Base Seasonal Delivering and Off-Taking Average TLMs (from Task 1) – SUMMER

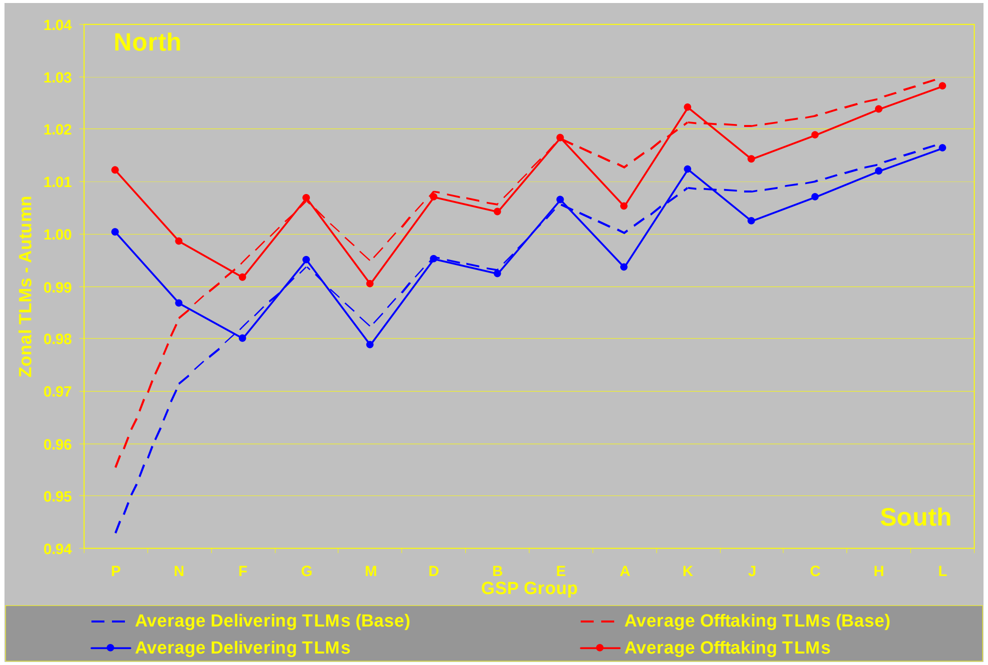

Figure 73: Seasonal Delivering and Off-Taking Average TLMs for Task 10 as compared to Base Seasonal Delivering and Off-Taking Average TLMs (from Task 1) – AUTUMN

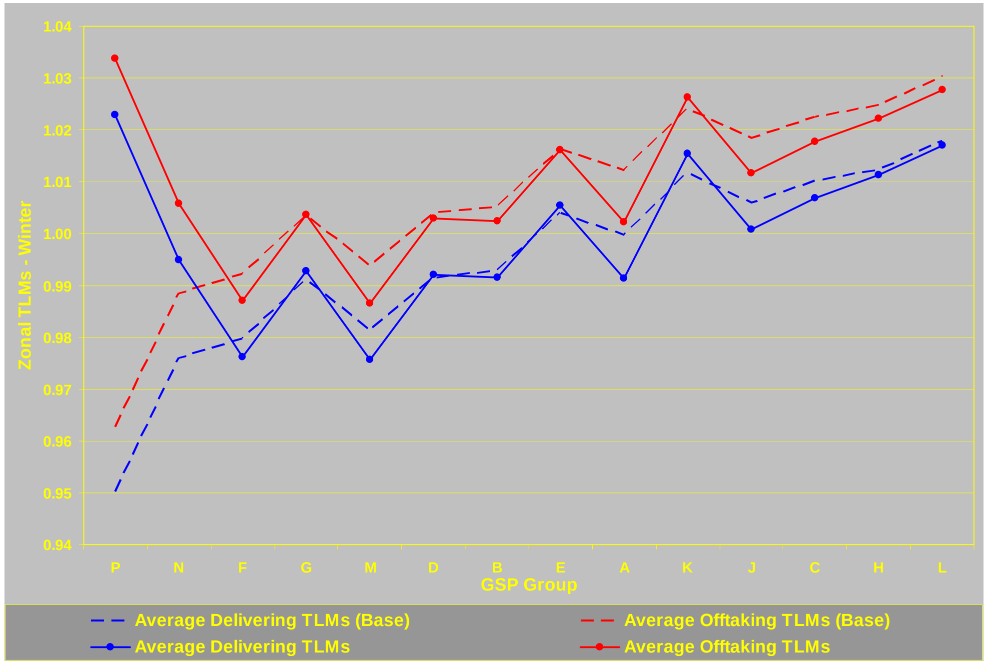

Figure 74: Seasonal Delivering and Off-Taking Average TLMs for Task 10 as compared to Base Seasonal Delivering and Off-Taking Average TLMs (from Task 1) – WINTER

6 AN ISSUE WITH THE METHOD FOR CALCULATING SP ZONAL TLFS

The issues with the way Zonal TLFs are calculated for a particular SP (as a volume weighted average), while noted in the past, were explored further on this occasion.

Nodal TLFs for a particular SP represent allocation of total system heating losses to the nodes that is true to the marginal theory, the method employed in the core of the proposed BSC modification. Application of these Nodal TLFs to the corresponding Nodal Power Flows provides “recovery” from the individual nodes, i.e. determines the contribution to the total system heating losses from the individual nodes. Inevitably, introduction of Zonal TLFs for a particular SP (where Zonal TLFs are some kind of average) introduces a degree of re-allocation of losses (thus the re-allocation of costs as well) between the nodes within each particular zone. The focus of this section is on the nature of these re-allocations. This section also reviews several alternative methods for calculating Zonal TLFs. An overview summary on these methods is presented in Section 6.5.

6.1 Method A – the method used in this Load Flow Modelling project

This method is also described and referenced in Section 4.1. This method uses absolute values of the Nodal Power Flows as volumes in the volume weighted averaging process. This method produces one unique Zonal TLF in each zone.

For each Sample Settlement Period (SSP) the Zonal TLF (ZTLFj) for each Zone j is 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 delivering and off-taking metered volumes); and ***(iii)*** where ΣN is summation over the Nodes in a Zone. For guidance on the zones see Section 5.1.

The observation was that such a ZTLFj value does not recover the same losses as the NTLFj values recover in that same zone. The extent of the discrepancy in the recovery of losses is not systemic across the zones. Thus there is an additional non-systemic re-allocation of losses between the zones. There is a re-allocation of losses between all nodes in a zone, thus between delivering and off-taking nodes in the zone as well. The method is numerically robust. It does not show any excessive re-allocation of losses within a zone. There are no particular problems in practical application of this method.

6.2 Method B – method using “direct” Nodal Power Flows

This method uses values of the Nodal Power Flows directly, i.e. with their original sign, as volumes in the volume weighted averaging process. This method produces one unique Zonal TLF in each zone.

The convention is that delivering metered volumes have positive sign and that off-taking 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 value does recover exactly the same total system heating losses as the NTLFj values recover in that same zone. Therefore, this method does not re-allocate these losses between the zones. 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 could be extremely out of proportion. Although such cases are highly improbable this approach was not acceptable for a live application. There is a re-allocation of losses between all nodes in a zone, thus between delivering and off-taking nodes in the zone as well. Even though the method is unacceptable there are no particular problems in practical application of this method.

6.3 Method C – method using least square errors (LSE) technique on the "nodal recoveries"

This method minimises differences between nodal recoveries when using Nodal TLFs and when using Zonal TLFs. This method produces one unique Zonal TLF in each zone.

This method focuses on recoveries from individual nodes in a particular zone that are obtained by using Nodal TLFs for these nodes in the zone and by using the Zonal TLF for that particular zone. The method determines a single Zonal TLF that minimises squared departure of nodal recoveries when using this Zonal TLF from nodal recoveries when using Nodal TLFs. Such a Zonal TLF is calculated as $ZTLFj = \Sigma N\ (NTLFj * NQMj^2)\ /\ \Sigma N\ NQMj^2$ (the terms in this formula are explained in Section 6.1 and Section 6.2).

Although this method is better theoretically founded than method A (Section 6.1) its Zonal TLFs have very similar characteristics as Zonal TLFs obtained using method A (see also **Table 19** and **Figure 75**).

6.4 Method D – method separates delivering and off-taking nodes in a zone

This method produces two Zonal TLFs in each zone, one for delivering nodes and one for off-taking nodes. This method uses values of the Nodal Power Flows directly, i.e. with their original sign, as volumes in the volume weighted averaging process.

If in each zone nodes with positive net Nodal Power Flows ("delivering" nodes) and nodes with negative net Nodal Power Flows ("off-taking" nodes) are treated separately, using $ZTLFj = \Sigma N\ (NTLFj * NQMj)\ /\ \Sigma N\ NQMj$ formula (i.e. $^{+}ZTLFj = \Sigma N\ (NTLFj * {}^{+}NQMj)\ /\ \Sigma N\ {}^{+}NQMj$ and $^{-}ZTLFj = \Sigma N\ (NTLFj * {}^{-}NQMj)\ /\ \Sigma N\ {}^{-}NQMj$ respectively; the terms in these formulae are explained in Section 6.1 and Section 6.2), then there would be two separate Zonal TLFs per Zone for each SP. Still, as required by the MP229 there would be unique zones for both delivering and off-taking nodes, but in each such unique zone there will be separate Delivering Zonal TLF and Off-Taking Zonal TLF and for each SP (i.e. before temporal averaging).

Table 19: Overview of selected characteristics of the SP Zonal TLFs as calculated with different methods described in Section 6

Issue	Method A	Method B	Method C	Method D
Does it recover correct zonal looses (i.e. the same as the Nodal TLFs)?	No	Yes	No	Yes
Is it robust with regard to any numerical problems?	Yes	No	Yes	Yes
Does it prevent excessive inter-zone re-allocation of losses?	Yes	No	Yes	Yes
Does it prevent uncontrolled re-allocation of losses between zones?	No	Yes	No	Yes
Does it prevent re-allocation of losses between generation and demand within a zone?	No	No	No	Yes
Is it practically applicable (i.e. not encountering application problems)?	Yes	Yes	Yes	No

Such Delivering Zonal TLF and Off-Taking Zonal TLF do recover the same total system heating losses as the Nodal TLFs recover in that same zone. Thus there are no re-allocations between the zones. There are no potential numerical problems. There are no inter-zone excessive re-allocations of losses. There are re-locations of losses between nodes of delivering type in the zone and between off-taking type in the zone, but there are no re-allocation of losses between delivering and off-taking nodes in the zone. However, there are some practical problems that some nodes may change their delivering/off-taking status over different SPs and that there are some market participants that would be difficult to associate with the correct Delivering Zonal TLF/Off-Taking Zonal TLF in their zone.

6.5 Summary of methods for calculating SP Zonal TLFs

Table 19 summarises the characteristics of SP Zonal TLFs produced using different methods reviewed in Section 6. **Figure 75** illustrates SP Zonal TLFs produced using different methods reviewed in Section 6 (the particular SP used for this illustration does not belong to the 630 SSPs selected for this project).

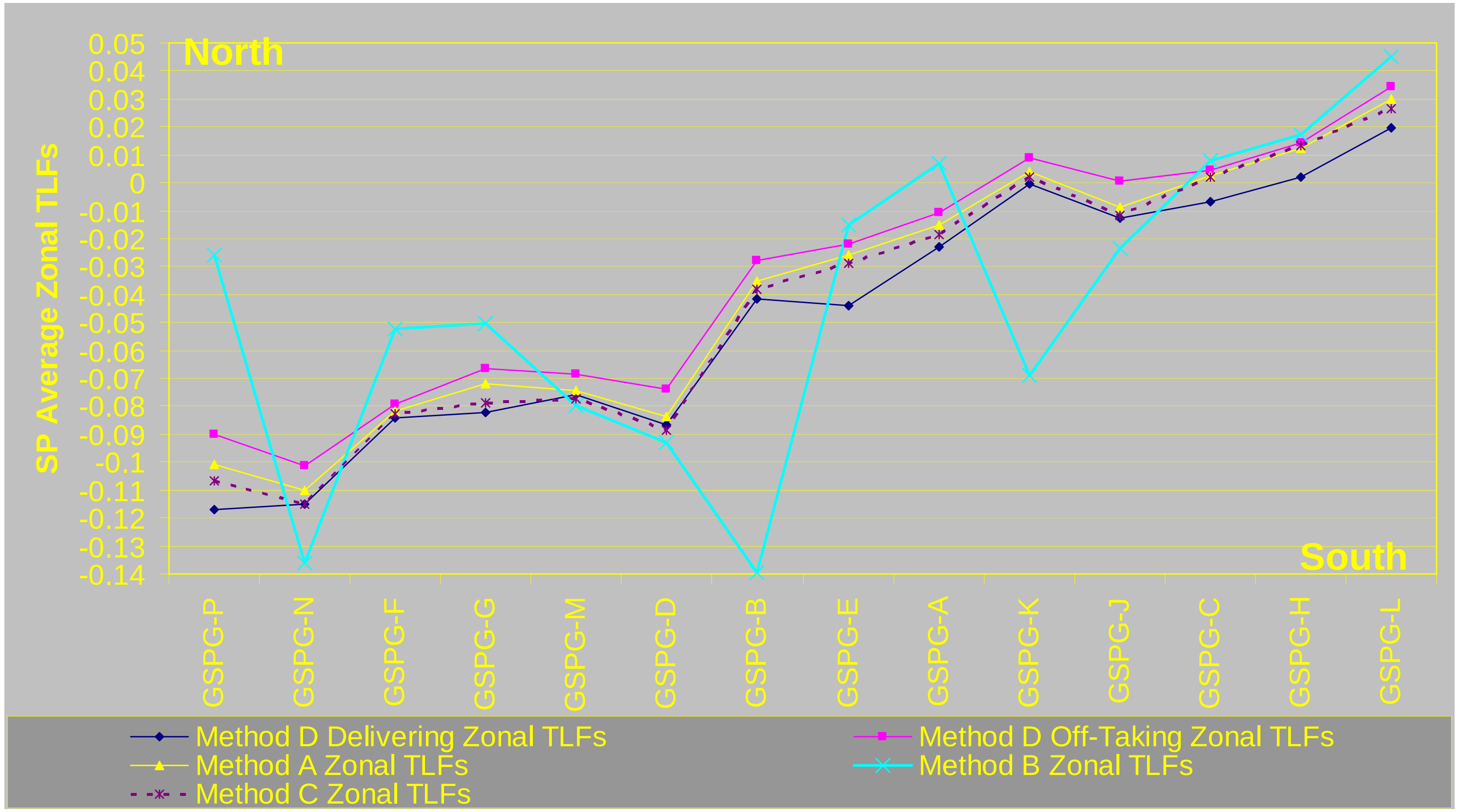

Figure 75: Illustration of SP Zonal TLFs produced using different methods reviewed in Section 6