Locational-based Coupling of Electricity Markets: Benefits from Coordinating Unit Commitment and Balancing Markets

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September 2010

CWPE 1044 & EPRG 1022

EPRG WORKING PAPER

UNIVERSITY OF CAMBRIDGE

Electricity Policy Research Group

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EPRG Working Paper 1022

Cambridge Working Paper in Economics 1044

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Abstract

We formulate a series of stochastic models for committing and dispatching electric generators subject to transmission limits. The models are used to estimate the benefits of electricity locational marginal pricing (LMP) that arise from better coordination of day-ahead commitment decisions and real-time balancing markets in adjacent power markets when there is significant uncertainty in demand and wind forecasts. The unit commitment models optimise schedules under either the full set of network constraints or a simplified net transfer capacity (NTC) constraint, considering the range of possible real-time wind and load scenarios. The NTC-constrained model represents the present approach for limiting day-ahead electricity trade in Europe. A subsequent redispatch model then creates feasible real-time schedules. Benefits of LMP arise from decreases in expected start-up and variable generation costs resulting from consistent consideration of the full set of network constraints both day-ahead and in real-time. Meanwhile, using LMP to coordinate adjacent balancing markets provides benefits because it allows intermarket flow schedules to be adjusted in real-time in response to changing conditions. These models are applied to a stylised four-node network, examining the effects of varying system characteristics on the magnitude of the locational-based unit commitment benefits and the benefits of intermarket balancing. Although previous

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studies have examined the benefits of LMP, these usually examine one specific system, often without a discussion of the sources of these benefits, and with simplifying assumptions about unit commitment.

We conclude that both categories of benefits are situation dependent, such that small parameter changes can lead to large changes in expected benefits. Although both can amount to a significant percentage of operating costs, we find that the benefits of balancing market coordination are generally larger than the unit commitment benefits.

Keywords electricity prices, international electricity exchange, electricity market model, electricity transmission

JEL Classification L94

Contact hweijde@feweb.vu.nl
Publication September 2010
Financial Support Flexnet

Locational-based Coupling of Electricity Markets: Benefits from Coordinating Unit Commitment and Balancing Markets[1]

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8 September 2010

1. Introduction

European electricity markets have changed profoundly in the last decades. Increased deregulation and privatisation have accompanied the decoupling of transmission, distribution and generation activities in national electricity markets. At the same time, markets are becoming increasingly interconnected. Moreover, rapid growth of renewable generation is leading to more operational uncertainty, which will encourage even more interconnection in the future. As a consequence of these developments, the need for an efficient congestion pricing mechanism to facilitate international electricity trade in Europe while respecting transmission and security constrains is becoming increasingly important (Brunekreeft et al. 2005; Hobbs et al. 2005).

At present, interconnection capacity between most European countries is auctioned day ahead or earlier, and not explicitly coordinated with the operation of energy markets. The amount of available transmission capacity, called Net Transfer Capacity (NTC), is determined by transmission system operators (TSOs).[2] For three reasons, these NTCs are generally set lower than the sum of

[1] This project is supported by EPSRC Supergen Flexnet and US National Science Foundation funding. We are grateful for suggestions by Cedric De Jonghe (KU Leuven), Karsten Neuhoff (CPI Berlin), Bert Willems (Univ. Tilburg), members of the Flexnet Markets & Investments working group and participants of the CPI workshop on Renewables Integration.

[2] In reality, there is a difference between NTCs, which in Europe are published twice a year as market guidance, and Available Transmission Capacities (ATCs), which are usually calculated day-ahead for a whole day and represent the actual amount of trade that will be allowed. ATCs for any given day can differ significantly from the earlier announced NTCs. In our analysis, we do not make a distinction between the two, but simply refer to the amount of transmission capacity that can be auctioned as NTC.

the thermal current limits of the constituent individual transmission lines. First, spare capacity needs to be provided to ensure system security. In particular, in case of generator or line outages, flows may suddenly increase between the countries, which need to be accommodated safely. Secondly, interconnections often consist of several individual circuits, so that, depending on the precise locations and amounts of load and generation, it is possible that individual circuits may be overloaded even though the total flow is less than the sum of the thermal capacities of the constituent circuits. Third, in the absence of a locational pricing system, the locations and levels of generation and load are not precisely known at the time of the day-ahead auction, so the exact pattern of flows between countries will also be uncertain. Thus, the TSO will generally set NTCs to a conservatively low level to ensure feasibility of those flows. However, even with those precautions, some scheduled flows might still be infeasible in real time and redispatch will be necessary. On the other hand, if spare capacity is available in real time, there may be opportunities for incremental trade between balancing markets. However, the economic value of that trade may be less than if the opportunity had been anticipated when committing generators, because once committed, the generation system's flexibility is limited in real time.

Another inefficiency in present market designs that locational-based pricing can address is the lack of coordination of balancing mechanisms in different markets. Presently, TSOs in adjacent European countries manage transmission constraint violations and unscheduled imbalances by redispatch within their own market areas, while attempting to maintain day-ahead schedules of international power exchange (Oggioni & Smeers 2009). If neighbouring operators could coordinate their balancing markets while respecting locational constraints, redispatch costs could be reduced and additional trading opportunities taken advantage of.

Clearly, the use of NTCs to limit day-ahead trade rather than the actual network constraints cannot, at least in theory, maximize expected net welfare. This is also true of the failure to coordinate real-time redispatch in adjacent markets. An alternative, which is implemented in several markets around the world and is currently being considered by the European Union, is locational marginal pricing (LMP) in both day-ahead and real-time markets. LMP is also known as nodal pricing, flow-based allocation or market splitting. As described by Schweppe et al. (1988), a nodal pricing system defines a marginal price at each location and time period that reflects the cost of delivering power to that location at that time, given the transmission constraints. Hsu (1997) gives a detailed explanation of this process. These prices are obtained by clearing energy and transmission markets simultaneously in a single optimisation model, recognising the impact of all network constraints. LMP is now used in by TSOs in six regional markets in the U.S.; O'Neill et al. (2006) provide an overview of US LMP systems, and Price (2007) describes one implementation in detail. If LMP could be implemented Europe-wide, international transmission would not have to be auctioned off. Instead, transmission capacity could be allocated by pricing constraints efficiently in multicountry day-ahead and real-time energy markets.

Introducing an Europe-wide LMP system could enhance power market efficiency in several ways. Short-term efficiency improvements include more efficient unit commitment, improved dispatch within countries, allocative efficiency improvements (from more efficient pricing of power to demand), cost decreases, market power reductions from increased international trade, and increased security of network operation through increased visibility. Meanwhile, potential long-term efficiency improvements can arise from better siting of power plants and industrial loads, and possibly the substitution of better management of existing transmission assets for transmission investment. Brunekreeft et al. (2005) discuss some of these effects in more detail.

Our work explores the determinants of two specific components of the benefits of considering network constraints via LMP. LMP-based market coupling avoids the use of NTC approximations in day-ahead unit commitment, and can facilitate coordination of redispatch and trade in adjacent markets in real-time. Our purpose is to quantify these benefits for a simple four-node network in order to explore the economic drivers that determine their magnitude.[3]

Many studies have recommended nodal pricing over other market designs (e.g., Chao et al. 2000; Ehrenmann and Smeers 2005; Brunekreeft et al. 2005; Imran and Bialek 2008), and some have estimated individual categories of LMP benefits for particular markets. Most of those analyses focus on allocative efficiency and dispatch improvements, with a few studies also reporting benefits resulting from more efficient international transmission and more efficient unit commitment. Green (2007) estimates that moving to LMP would provide efficiency benefits in the UK in the amount of 1.5% of generator revenues due to better dispatch and allocative efficiency. Leuthold et al. (2005) estimate a 0.6-1.3% increase in social surplus in Germany, with an additional 1% if more wind capacity is built, because that would increase congestion. They do not describe the exact sources of those benefits, but these include more efficient domestic dispatch and allocative efficiency. Weigt (2006) extends the model used in Leuthold et al. (2005) to include unit commitment of aggregations of power plants and international transmission; he obtains a benefit equal to 0.06% of the social surplus for the whole of Europe, the net effect of a 0.78% increase in consumer surplus and a 3.55% decrease in producer surplus. In the U.S., an empirical analysis of trade changes accompanying expansion of the Pennsylvania-New Jersey-Maryland (PJM) LMP system to the Midwestern U.S. found that gains from trade more than doubled between the original and newly included regions of PJM (Mansur and White 2009). The benefit was approximately $170M/year, compared to a one-time cost of $40M to extend PJM.

The study that is closest to our analysis of unit commitment benefits is Barth et al. (2009), who estimate an LMP benefit of 0.1% of the total system operation cost, as a result of more efficient international transmission, domestic dispatch and unit commitment of aggregations of generators. Their analysis does not attempt to disaggregate these benefits by category, nor do they undertake sensitivity analyses. Because each country is treated as a zone without considering individual circuits between countries or congestion within countries, this estimate should be viewed as a lower bound.

There are fewer quantitative analyses of the benefits of international redispatch, although there is a large amount of literature that argues for its

[3] It is possible that the international redispatch benefits could be realised by balancing mechanisms other than coupled LMP systems. To the extent that TSO efficient coordination by be achieved by other systems, our estimates of this category of benefits are relevant to evaluation of those mechanisms.

adoption (e.g., Meeus et al. 2005; Vandezande et al. 2008, 2010). Oggioni and Smeers (2009) use a simple network similar to ours to study the benefits of coordinating international redispatch arising from the coupling of electricity markets. They find that market coupling with LMP is more efficient than using NTCs and that, in a system with NTCs, international coordination is more efficient than domestic-only redispatch for adjusting schedules in order to meet all transmission constraints (saving 0.4 €/MWh or more, for the system analysed). Their benefit estimates are likely to be low because they include neither benefits arising from better unit commitment (as commitment decisions are not considered) nor benefits of coordinating balancing markets in the face of uncertain loads and supplies (as their model assumes no uncertainty). Meanwhile, Vandezande et al. (2009) estimate the benefits of cross-border balancing between Belgium and The Netherlands (compared to no international redispatch) to be around 40% of the total balancing costs.

Next, we present the methodology and model formulation. Data assumptions are summarised in section 3, followed by the results in section 4 and conclusions in section 5.

2. Method

We use stochastic (two-stage) programming to find the unit commitment (first-stage) and redispatch (second stage) decisions that minimize expected system costs over the distribution of possible real-time conditions. Doing this considering the full set of transmission constraints in both stages will, by the definition of optimisation, yield expected costs that are no worse than the expected cost resulting from a heuristic approach considering only approximate NTC constraints at the commitment stage and waiting until real-time to impose the actual network constraints. However, in practice, the consideration of network constraints in unit commitment may not be better because of other approximations used by market operators, such as deterministic security constraints or the use of a single demand or wind scenario to make commitment decisions. To avoid spurious results due to arbitrary choice of such constraints or scenarios, we use stochastic optimisation models, in which the contingencies that motivate operating reserves are explicitly represented. With these models, we can analyse the benefits of LMP in isolation, without the picture being muddied by other market imperfections.

We consider the simple network in Fig. 1. There are two countries or markets, each having two nodes, or 'buses.' These buses are connected by four lines, and the only contingencies we consider in our main analyses are load and wind variations in Country 2 (nodes C and D). As a sensitivity analysis, we consider variations at A and B as well. However, our modelling approach is general and can be used for a system with more buses and other types of random events.

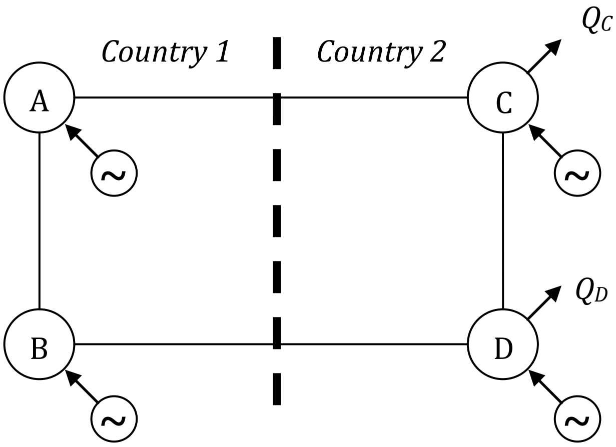

Fig. 1 Assumed network

We consider two basic models, where the first has two variants. The first basic model is Model NTC, which is a sequence of two decision stages. The day-ahead unit commitment problem is first solved subject to an NTC between the two countries, followed by real-time redispatch, which is conducted subject to the actual network constraints and wind/demand realisations, as well as the previously determined commitment schedule. The second basic model is Model LMP, in which the unit commitment problem is instead solved subject to the full network constraints. Two different instances of model NTC are examined. In the first, real-time redispatch (or 'balancing') is coordinated (NTC-ID), so that real-time schedules can differ under different realisations of real-time load and wind. The other allows only domestic redispatch, maintaining the same total MW of international flow as scheduled day-ahead (NTC-NID). Fig. 2 gives a schematic overview of the sequence of calculations for each model.

In each case, unit commitment is day-ahead for 24 hours. For simplicity, we group these hours into three time periods representing peak, off-peak and shoulder hours. The only commitment costs are start-up and minimum run ('fixed') costs, and the only commitment constraints are minimum run constraints; ramp limits and minimum shut-down or operating times are not considered. When making commitment decisions, net load (load net of wind generation) is unknown. Instead, there are several net load scenarios, each with a known probability. In all models in real time, the committed generators are dispatched against the realised net load recognising the actual network constraints. We assume that all generators truthfully bid their costs and commitment constraints, and do not attempt to exercise market power. A different model formulation would be required to estimate the benefits of locational-based market coupling resulting from a reduction of market power or the avoidance of generator gaming. These are different categories of benefits than those examined here, and without the scope of this paper.

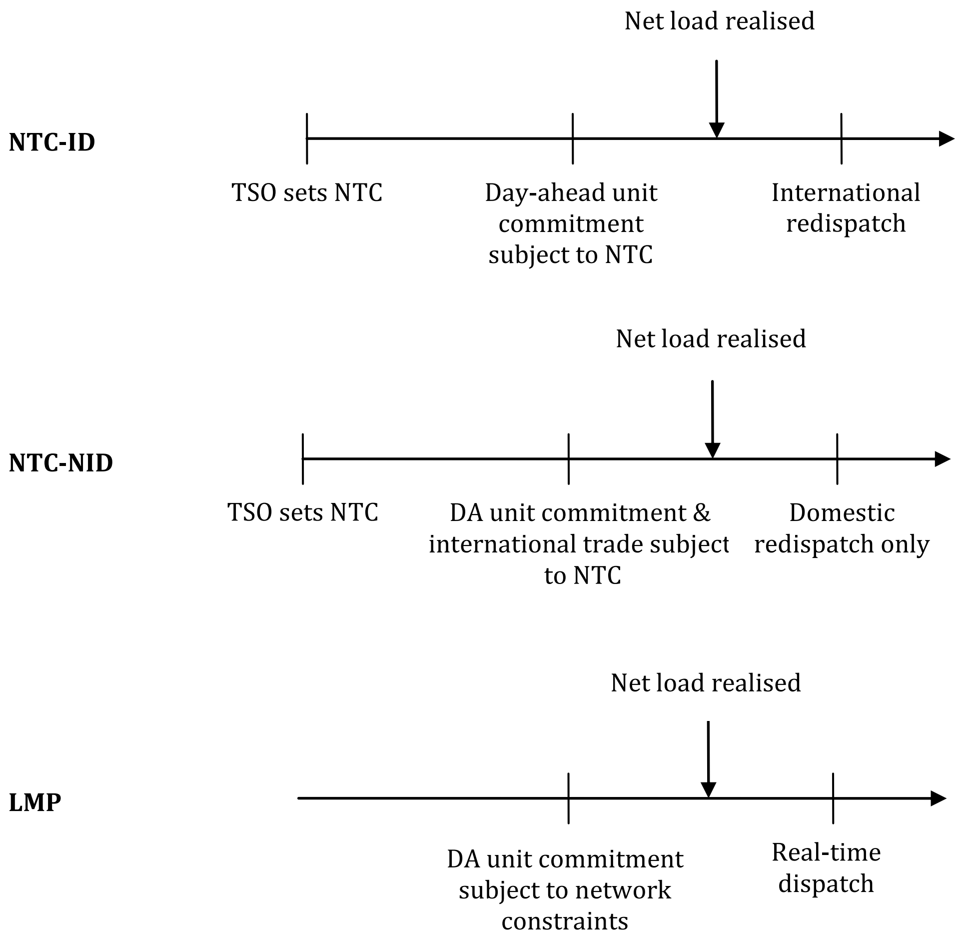

Fig. 2 Sequence of decisions and calculations in models

2.1. Notation

Sets		*indexes*
H	Nodes	h
I	All generators	i
I^h	Generators at node h	i
I^X	Electricity sinks (in overgeneration situation)	i
I^{CONV}	Thermal generators	i
I^{CT}	Combustion turbines	i
J	Real-time net load scenarios	j
K	Transmission lines	k
T	Time periods	t

Parameters	
CL	Real-time penalty for deviating from day-ahead international schedules [$/MWh]
FC_i	Fixed cost of generator i if committed [$/h]
H_t	Length of time period t [hours]
MC_i	Marginal cost of generator i [$/MWh]
NTC	Net transfer capacity in the NTC unit commitment model [MW]

$P_i^{\min}$	Minimum run level of generator *i*, if committed [MW]
$P_i^{\max}$	Maximum run level of generator *i*, if committed [MW]
$PTDF_{hk}$	Power transmission distribution factor describing the effect upon flow on line *k* as a result of a unit power injection at *h* consistent with the linearised DC load flow model [MW/MW].
PR_j	Probability of scenario *j*
Q_{hjt}	Quantity demanded, net of wind output, at node *h* in scenario *j*, period *t* [MW]
SU_i	Start-up costs of generator *i* [$/start]
T_k	Flow constraint on transmission line *k* [MW]
	Decision variables
s_{it}	Binary variable representing the decision to start-up generator *i* in time period *t*
z_{it}	Binary variable representing the decision to operate generator *i* in time period *t*
p_{ijt}	Generation by generator *i* in real-time scenario *j*, time period *t* [MW], as anticipated by the unit commitment model
$\bar{p}_{ijt}$	Actual real-time dispatch of generator *i* in scenario *j*, time period *t* [MW]
l_{jt}	Shortfall of real-time international power flow from day-ahead schedule in scenario *j*, time period *t* [MW]

2.2. Model NTC

Unit commitment stage

Given the notation above, the objectives of both models NTC and LMP are the start-up and fixed commitment costs plus the expectation (over real-time scenarios) of variable costs:

$$\min_{\{s_{it}, z_{it}, p_{ijt}\}} \sum_{t \in T} \left[\sum_{i \in I} (SU_i s_{it} + H_t FC_i z_{it}) + \sum_{j \in J} PR_j H_t \sum_{i \in I} MC_i p_{ijt} \right] \quad (1)$$

This is optimised subject to the following constraints. The first set allows generation only if a unit is committed (z_{it} = 1), and force start-up costs to be incurred (s_{it} = 1) if a unit is committed in one period after being off:

$$P_i^{\min} z_{it} \le p_{ijt} \le P_i^{\max} z_{it} \qquad \forall i \in I^{CONV}, j, t \quad (2)$$

$$z_{it} - z_{i,t-1} \le s_{it} \qquad \forall i \in I^{CONV}, t \quad (3)$$

$$s_{it} \ge 0 \qquad \forall i \in I^{CONV}, t \quad (4)$$

Combustion turbines are included to avoid infeasibilities in real time; they have no maximum or minimum run levels, but they have to produce non-negative amounts of power:

$$p_{ijt} \ge 0 \qquad \forall i \in I^{CT}, j, t \quad (5)$$

We assume ample such capacity, and so do not include an upper bound. Electricity sinks are also included to avoid infeasibilities in Country 1 in overgeneration situations; they can only consume power (which is modelled as production of non-positive amounts of power), at a cost.

$$p_{ijt} \leq 0 \qquad \forall i \in I^X, j, t \qquad (6)$$

Load has to be met in every scenario:

$$\sum_{i \in I} p_{ijt} = \sum_{h \in H} Q_{hjt} \qquad \forall j, t \qquad (7)$$

Country 1 cannot produce more power than the NTC allows it to export:

$$\sum_{i \in I^A} p_{ijt} + \sum_{i \in I^B} p_{ijt} \leq NTC \qquad \forall j, t \qquad (8)$$

As mentioned, we examine two instances of this model; one in which international redispatch is possible (NTC-ID), and one where the total amount of electricity traded from A to B in real-time in all scenarios is to adhere to the day-ahead schedule (NTC-NID) subject to imbalance penalties. In the version of the model in which no international redispatch is allowed in real-time (NTC-NID), we impose the same international flow in every scenario j:

$$\sum_{i \in I^A} p_{ijt} + \sum_{i \in I^B} p_{ijt} = \sum_{i \in I^A} p_{i,j+1,t} + \sum_{i \in I^B} p_{i,j+1,t} \qquad \forall j < |J| \qquad (9)$$

However, we omit this constraint for NTC-ID, and flows can depend on the real-time scenario.

Dispatch stage

In real time, start-up and fixed costs are sunk, so only the variable costs and the costs of not meeting the committed interregional transmission flow are minimised:

$$\min_{\{\bar{p}_{ijt}, l_{jt}\}} \sum_t H_t \left(\sum_{i \in I} MC_i \bar{p}_{ijt} + l_{jt} CL \right) \qquad (10)$$

Constraints (11) – (14) are similar to those in the unit commitment stage:

$$P_i^{\min} z_{it}^* \leq \bar{p}_{ijt} \leq P_i^{\max} z_{it}^* \qquad \forall i, j, t \qquad (11)$$

$$\bar{p}_{ijt} \geq 0 \qquad \forall i \in I^{CT}, j, t \qquad (12)$$

$$\bar{p}_{ijt} \leq 0 \qquad \forall i \in I^X, j, t \qquad (13)$$

where z_{it}^* is the optimal value of z_{it} from the unit commitment model. The energy balance is:

$$\sum_{i \in I} \bar{p}_{ijt} = \sum_{h \in H} Q_{hjt} \qquad \forall j, t \qquad (14)$$

Instead of constraint (9), flows are now constrained by the full set of network constraints:

$$\sum_{h \in H} PTDF_{hk} \left(\sum_{i \in I^h} \bar{p}_{ijt} - Q_{hjt} \right) \leq T_k \qquad \forall k, j, t \qquad (15)$$

As mentioned above, in the version of the model without international redispatch in real-time (NTC-NID), the redispatch in each j must result in the same total MW flow between the two countries as the day-ahead commitment model calculates unless a schedule deviation penalty $l_{jt}CL$ is paid. The possibility of schedule deviations must be considered because completely fixing the total trade in A and B could lead to infeasibilities. The following constraints define a nonnegative shortfall l_{jt} as the difference between the scheduled and real-time flow from Country 1 to Country 2. Only shortfalls in real-time flows need to be considered, since excess flows can be avoided by taking advantage of electricity sinks in nodes A and B.

$$\sum_{i \in I^A} \overline{p}_{ijt} + \sum_{i \in I^B} \overline{p}_{ijt} + l_{jt} = \sum_{i \in I^A} p^*_{ijt} + \sum_{i \in I^B} p^*_{ijt} \qquad \forall k, j, t \qquad (16)$$

$$l_{jt} \geq 0 \qquad \forall j, t \qquad (17)$$

where p^*_{ijt} is the generation anticipated in the commitment stage, and is treated as a fixed parameter in the real-time model.

2.3. Model LMP

Unit commitment stage

The only difference between the NTC and LMP models is that the LMP unit commitment and real-time stages use the same (full) set of transmission constraints. Hence, Model LMP minimises (1) subject to constraints (2) – (7) and

$$\sum_{h \in H} PTDF_{hk} \left(\sum_{i \in I^h} p_{ijt} - Q_{hjt} \right) \leq T_k \qquad \forall k, j, t \qquad (18)$$

Dispatch stage

Model LMP's real-time objectives and constraints are the same as those for Model NTC-ID. Note that for the LMP model, p^*_{ijt} is also an optimal solution in real time, and so it is not necessary to solve the dispatch model separately. Solving equation (1) subject to (2)-(7), (18) solves the entire problem.

2.4. Calculating the benefit of LMP and international redispatch

Letting $\overline{p}^*_{ijt}$ be the optimal dispatch value from the dispatch model, we can then calculate the total actual expected cost for each model as the sum of the start-up and fixed commitment costs from the unit commitment stage plus the expected (across real-time scenarios) variable costs from the redispatch stage:

$$E[TC] = \sum_{t \in T} \left[\sum_{i \in I} SU_i s^*_{it} + H_t FC_i z^*_{it} + \sum_{j \in J} PR_j H_t \sum_{i \in I} (MC_i \overline{p}^*_{ijt} + l_{jt} CL) \right] \qquad (19)$$

This is done both for the NTC and LMP models. Subtracting the LMP model cost from the NTC-NID model cost yields an estimate of the total benefits of LMP, including both the unit commitment and international redispatch (balancing market coordination) benefits of considering network constraints day-ahead and in real-time. Meanwhile, comparing just the NTC-ID and LMP costs gives an estimate of only the unit commitment benefits, while the difference between the NTC-NID and NTC-ID costs represents the incremental benefits of international redispatch.

The degree of distortion of costs because of the use of the NTC constraint in the unit commitment stage of Model NTC, rather than actual flow constraints (as in the LMP model), will depend on the MW of NTC that is imposed day-ahead. In order to avoid overstating the benefits of LMP because of a poor choice of NTC, we report a set of results in which we tune the value of NTC in each run of Model NTC in order to minimize expected unit commitment and actual dispatch costs from that model (Eq. 19), and then compare those costs to the objective function of Model LMP, as just described. This simulates a NTC definition process in which the neighbouring TSOs cooperate to determine a single limit on flows to be applied in all time periods of the day that will give the most economic benefit, guarding against infeasibilities that might arise under extreme demand and wind scenarios. In addition, we will also compute those benefits for fixed values of NTC (85% of thermal line capacities) to show how much larger the estimated benefits of LMP would be if operators do not tune NTC in that manner. The latter situation is arguably more realistic, since NTCs are usually chosen day-ahead for a whole day.

3. Data assumptions

Assumed generator start-up costs, marginal operating costs and fixed costs are shown in Table 1. These values were based upon Bard (1988), with the following changes. Units were renumbered for convenience. Start-up costs were calculated as the average between a hot start-up and a cold start-up. The assumed variable cost per MWh was calculated in three steps. First, we calculated Bard (1988)'s assumed marginal operating cost at the midpoint of each unit's operating range. Then, we increased the variation in marginal costs among generators in the sample to make them more representative of cost variations among plants in 2010 by expanding the range of marginal costs by a factor of four by the following transformation:

$$MC_i \leftarrow 4(MC_i - MC^{\min}) + MC_i \qquad (20)$$

where $MC^{\min}$ is the smallest value of MC_i among units *i*. The next change was to double fixed, marginal and start-up costs to reflect two decades of inflation. This results in a dataset with similar ratios of start-up and fixed costs to variable costs as the plants in Shaw (1995), Kazarlis et al. (1996), and a recent sample of generators in The Netherlands. The plants were then distributed among the nodes so that cheaper generation tends to be in Country 1, so that it will tend to export power to Country 2. The final modification to Bard (1988)'s dataset was to add combustion turbines at nodes C and D to avoid having inadequate generation and imports to meet load, and power sinks (called X_i in Table 1) at all nodes to avoid infeasibilities due to overgeneration.

Table 1 Generation costs and parameters

i	$P_i^{\max}$	$P_i^{\min}$	FC_i	MC_i	SU_i	Location
Unit 1	200	50	350	15.40	2860	A
Unit 2	375	110	800	20.18	2470	A
Unit 3	250	75	400	27.25	2430	A
Unit 4	400	130	800	19.20	2760	B
Unit 5	420	130	840	26.85	2780	B
Unit 6	850	275	1450	27.24	4100	B
Unit 7	600	165	1200	31.56	4000	C
Unit 8	700	225	1080	41.47	3900	C
Unit 9	1000	300	1640	35.99	3700	D
Unit 10	750	250	1200	36.18	4200	D
CT 1	n/a		0	90.00	n/a	C
CT 2			0	90.00		D
X_A			0	-90.00		A
X_B			0	-90.00		B
X_C			0	-90.00		C
X_D			0	-90.00		D

For simplicity, we only consider variability in load net of wind generation in our scenarios; contingencies due to transmission or generation equipment outages are not included. With the exception of one sensitivity analysis, only Country 2 (nodes C and D) has uncertain net load. We consider four scenarios, and three time periods. Period 3, the peak hour, has the highest net load levels; they are listed in table 2. Net load levels in period 2 are 2/3 of peak load, and those in period 1 are 1/3 of peak load. Each period lasts for eight hours, resulting in a total number of 24 hours. The net load, in this case, represents the total demand for electricity at each node, net of the amount of power generated by wind turbines, and also net of the available baseload capacity. As baseload generation capacity (such as nuclear or large coal plants) is assumed to be always committed, its inclusion in the unit commitment and real-time dispatch models would not influence the commitment or generation decisions for other units, nor would it influence the unit commitment benefits of LMP or the benefits of international redispatch. To reduce computational intensity, we therefore subtract the baseload capacity from the load. However, this does mean that where we express LMP benefits as fractions of the total system costs, these costs exclude the expense of operating baseload plant (and, of course, the capital costs of any plant).

The four scenarios consist of all possible combinations of low (L) and high (H) net load at nodes C and D. We assume $PR_{LL} = PR_{HH} = a$ (where the first subscript letter refers to C's outcome and the second refers to D's) and $PR_{LH} = PR_{HL} = 0.5 - a$, where a is initially set to 0.25 so that all scenarios have equal probabilities. This parameter can be interpreted as representing the correlation between net load at nodes C and D; when a is set to 1/2, there is a perfect positive correlation, when a is set to 0, there is a perfect negative correlation. The expected peak load at each node is independent of a.

Table 2 Peak load net of wind, Q_{hjPEAK}, in all scenarios (MW)

i	*HH*	*HL*	*LH*	*HH*
A	0	0	0	0
B	0	0	0	0
C	2200	2200	1000	1000
D	2200	1000	2200	1000

All transmission lines have a maximum capacity of 1000 MW and equal reactances. We use linearised DC approximations to calculate line flows. The scheduling imbalance penalty *CL* resulting from deviating from the international flow commitment constraint in Model NTC without international redispatch is assumed to be 90$/MWh. Thus, all penalties (flow deviation and overgeneration) are assumed to be the same as the cost of combustion turbines. Our results do not change significantly when these penalties are varied.

As noted above, we only consider day-ahead commitment for a single day, consisting of three time periods. Ramp rate limits, start-up costs that depend on the amount of time that a plant is shut down, and minimum down- or up-times are omitted.

4. Results

We used Gurobi 2.0.1 to solve both the mixed-integer programs (MIPs) that represent the unit commitment stage, and the linear programs (LPs) for the real-time dispatch. We first solve the models for the base case, using the assumptions above, after which we test the sensitivity of the results to changes in generation, transmission, and load parameters, in turn.

4.1. Base case

Model LMP by definition minimises expected unit commitment and dispatch costs subject to the actual network constraints. Model NTC finds a solution using a different (and incorrect) feasible region in the first stage, through the inclusion of an NTC rather than network flow constraints in the unit commitment model, followed by a redispatch to attain feasibility under the actual network constraints. Hence, by the definition of optimality, the unit commitment benefits of LMP as calculated by comparing eq. (19) for the LMP and NTC models can never be negative.

Fig. 3 shows the difference between the expected total costs of the NTC and LMP model solutions, and thus the nodal pricing benefits, as a percentage of expected total costs (expected dispatch costs for non-baseload generators) of the LMP model. These benefits are shown as a function of the assumed NTC. A range of 1000-2000 MW for NTC is considered because values outside that range cannot be optimal: each of the two lines has a capacity of 1000 MW, so total trade up to 1000 MW can always be accommodated, wherever generation and load are located, whereas trade higher than 2000 MW will never be feasible.

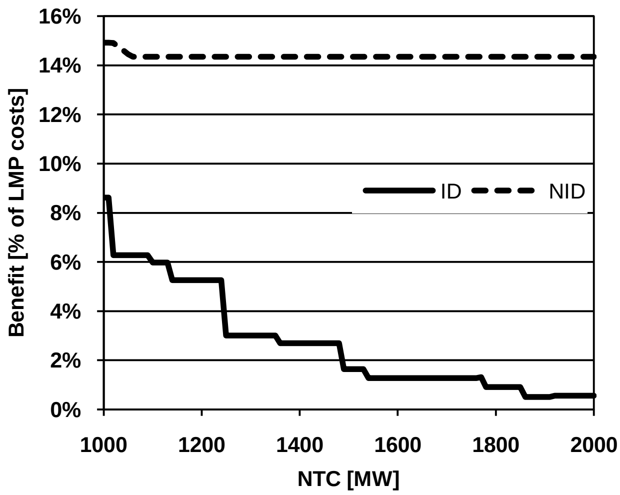

Fig. 3 Benefits as a function of NTC: Base case assumptions

From this graph, several conclusions can be drawn, although they depend on the assumed parameters, whose effects will be explored below. Firstly, the unit commitment benefits of LMP are significant. When international redispatch is possible and NTC can be set optimally so as to minimise the total start-up and variable costs of generation (between 1860 and 1920 MW, the lowest points on the solid line), they are still 0.51% of the total system costs under LMP. However, to achieve this, TSOs would have to know the generation costs for every generator, as well as the exact net load levels, and then set NTC for every day in order to minimize expected costs. In fact, TSOs do not, and indeed cannot, fine-tune NTC in this manner, which means that the actual benefits will be higher, e.g., 1.27% if the NTC is always set at 85% of the combined thermal capacity of the lines (1700 MW). When international redispatch is impossible, which reflects the current situation in most European markets, the unit commitment benefits of LMP are much higher, with a minimum at 14.25% of total system costs under LMP (the dashed line in Fig. 3).

Secondly, the benefits of being able to redispatch internationally are significantly higher than the unit commitment benefits of LMP, under the assumed parameters. This suggests that even if full market integration is not possible, more international coordination on redispatch in balancing markets could bring significant benefits. Such coordination would bring costs down from the dashed line to the solid line in the figure.

Finally, the benefits are relatively constant across the NTC-space when international redispatch is not possible, with only a minor increase for very small NTCs. This is a direct result of eq. (9), which specifies that a single dispatch schedule has to be committed to in the day-ahead unit commitment stage. This dispatch schedule has to be optimal across all scenarios and, since imbalance penalties are high, it will be set to avoid penalties from forced imbalances and overgeneration. Hence, conservative schedules and high levels of commitment in Country 2 will be chosen day-ahead so that if loads are high, rescheduling penalties can be avoided. Thus, if international redispatch is not possible, the NTC is less important in determining the unit commitment benefits of LMP, unless it is set very low, as NTC-NID schedules will generally be conservatively smaller than in the NTC-ID model. Typically, average international flows are lower in the NTC-NID model and, consequently, more units are committed at C and D. For example, for an NTC of 1700MW, the average international flow in the NTC-ID model is 1067 MW in the first, 1462 MW in the second, and 1499 MW in the third period. In the NTC-NID model, these flows are 502 MW, 600 MW and 1060 MW, respectively. This supports the above conclusion.

In the next subsections, we consider the robustness of these conclusions with respect to generator, load, and transmission assumptions. Only results for optimal NTCs and NTCs set at 85% of the combined thermal capacity of the two transmission lines are shown. Three-dimensional figures, which show the results for other NTCs, can be found in the appendix.

4.2. Generator size and total capacity

To explore the sensitivity of these results to the size of the generators, we vary the minimum run levels, maximum run levels, start-up costs and fixed costs by +/-50% by multiplying them by a constant ranging between 0.5 and 1.5. Thus, both generator size and total capacity change proportionally; in section 4.3, we will instead consider the effect of generator sizes holding total capacity fixed. Fig. 4 shows the benefits for three models: the NTC-ID model with optimal NTCs for every size multiplier; the same model with an NTC that is always set at 85% of the combined capacity of the two international lines (i.e., at 1700 MW); and the NTC-NID model with optimal NTCs.[4] In the NTC-NID model, an NTC of 1700 MW is always optimal. This is a result of the fact that NTC values matter relatively little in this model, as explained above.

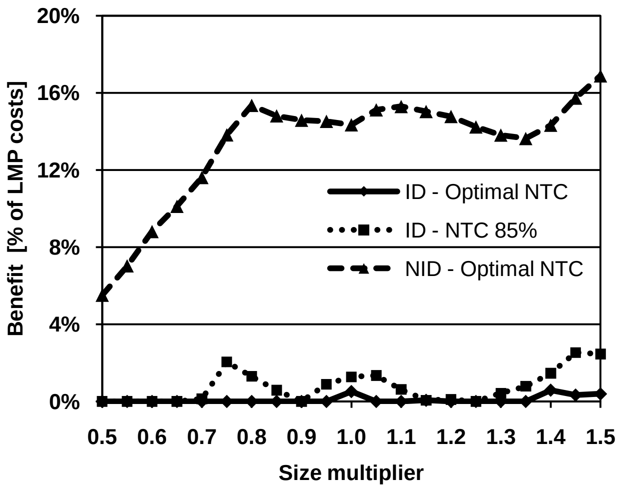

Fig. 4 Benefits as a function of generator size, with total capacity proportional to size

As Fig. 4 shows, the unit commitment benefits of LMP depend on the generator size. When international redispatch is possible, the relation between benefits and generator size is non-monotonic, and does not seem to follow a clear pattern, whether NTCs are set optimally or not. Under optimal NTCs, the benefits are zero for many size multipliers. When instead international redispatch is impossible, the relation between the size multiplier and the unit commitment benefits of LMP is also non-monotonic, but the benefits are significantly lower when generators are small. This happens because, as

[4] An NTC-NID model with NTCs set at 85% of the combined capacity of the two lines was also examined. However, the results from this model do not differ significantly from the NTC-NID model with optimal NTCs, and they are therefore not reported separately.

generators get smaller, total generation capacity also decreases. Hence, more and more generators have to be started up and committed in all scenarios, whatever their costs. As unit commitment benefits arise from sub-optimal commitment, and there is less room for sub-optimal commitment when there are fewer generators that can be left unused without compromising feasibility, these benefits shrink as size multipliers get smaller.

4.3. Generator size with fixed total capacity

In the above analysis, an increase in the capacity of every generator in the system yields a proportionate increase in total generating capacity. Thus, the effects observed may be because the balance of supply and demand is changed, or because the 'lumpiness' of commitment decisions is altered. In this and the next subsection, we consider the separate impact of generator size, while holding the ratio of total capacity to load constant. Although it is not possible to continuously increase the average generator size while keeping the total capacity constant, we can decrease the generator size by, e.g., doubling or quadrupling the number of generators and simultaneously decreasing their capacity so that total capacity does not change. We do this in this subsection, while in the next subsection we instead consider the effect of generator 'lumpiness' by varying just the minimum run level.

Figs. 5 and 6 compare the unit commitment benefits of LMP in the base case (size=s) with a model in which the number of generators is doubled, while cutting their min run and max capacity, start up costs, and fixed costs by 50% (size=s/2). The limit of this process of shrinking generator size can be represented by treating the 0-1 commitment variables as continuous rather than binary variables, such that any fraction can be committed. This results in a linear program. Thus, the third line in each figure (LP) plots the solution of such a relaxed version of the base case, in which all z_{it}'s are continuous variables in the range [0,1].

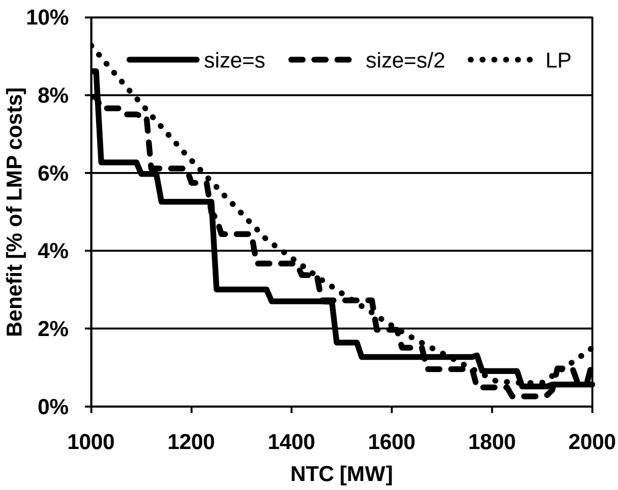

Fig. 5 Benefits as a function of generator size, NTC-ID, constant total capacity

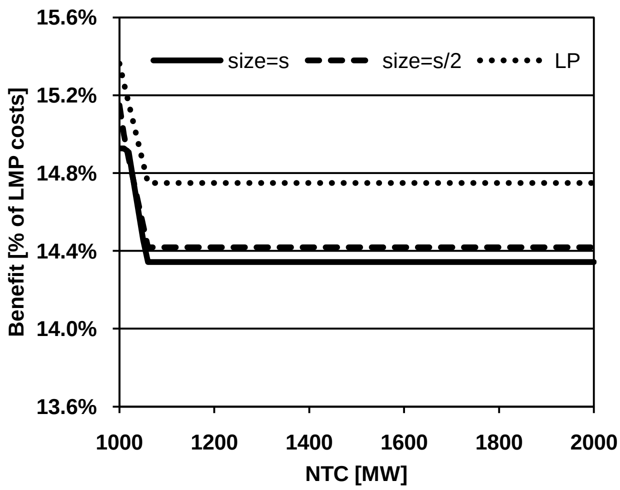

Fig. 6 Benefits as a function of generator size, NTC-NID, constant total capacity

Several phenomena can be observed in Figs. 5 and 6. First of all, the variations are not as large as observed in Fig. 4, indicating that generator size and total system capacity together affect benefits more than the size of individual units alone. Second, when international redispatch is possible (Fig. 5), the unit commitment benefits of LMP are higher when units are smaller for most values of NTC, including the optimal one. When international redispatch is not possible (Fig. 6), this relationship is always the case. Secondly, the LP formulation can significantly overstate the benefits. Although it understates them for some values of NTCs, when averaged over the entire range of NTC, the LP formulation overstates benefits by 0.91% for NTC-ID, and by 0.40% for NTC-NID. When NTCs are set optimally, the LP formulation overstates the benefits by 0.09% for NTC-ID, and by 0.41% for NTC-NID; however, for other NTCs, the overstatement is as large as 2.69% and 0.44%, respectively. This phenomenon occurs not only under the base case parameters, but also for others (not shown).

This difference between the MIP and LP formulations can be explained by examining the reserve capacity made available to the real-time market in each model. When the MIP formulation is used, generators are either started up and committed, in which case they have to produce output between their minimum and maximum run levels, or they are not started up and committed, in which case they cannot produce anything. In many cases, there will be at least one generator that is not producing at its maximum output level. This reserve capacity provides flexibility if, in real time, the actual transmission constraints allow more power to be transported across the two regions then was anticipated based on the NTC. However, as generators become smaller, the amount of capacity committed day-ahead can be more closely tailored to particular NTCs, reducing flexibility. In the extreme case of an LP formulation, just enough generation capacity will be committed to meet the maximum load and NTC constraints, and no spare capacity is available.

We conjecture that the upward bias an LP formulation can cause will be smaller in larger systems with few internal transmission constraints. In that case, individual units make up a smaller part of the total generation capacity in a transmission-constrained submarket, and hence unit commitment can already to a large extent be tailored to anticipated transmission capacity. An LP formulation may still overstate benefits, but perhaps not by as much as in our test system.

4.4. Generator minimum run levels

Another way of varying the size of generators while keeping the total generation capacity constant is to change just the minimum run levels, which we achieve by adjusting those levels by a multiplier. As Fig. 7 shows, the relation between the multiplier and the commitment benefits of LMP is again non-monotonic, whether international redispatch is possible or not. However, whereas for the NTC-ID model these benefits are relatively constant, for the NTC-NID model they increase with the minimum run multiplier.

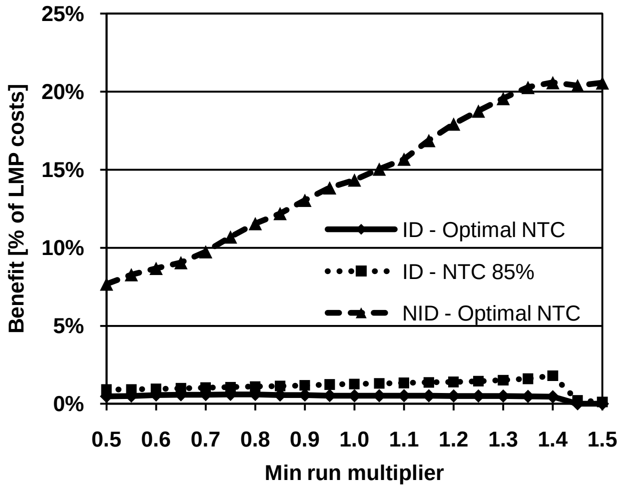

Fig. 7 Benefits as a function of minimum run levels

There are several reasons for these increasing benefits. First of all, increasing minimum run levels favours commitment of fewer generators, because spilling power when supply is in excess of demand is expensive. For a minimum run multiplier of 0.6, three units are committed in the first period, six in the second period, and eight in the third period. Increasing the multiplier to 1 (the base case) results in a reduction to five units in the second period. Increasing it even further, to 1.4, decreases the commitment further, to six units in the third period. When fewer units are committed, the chance that the committed set of units is sub-optimal relative to the realised real-time demand and wind is greater, leading to larger unit commitment benefits of LMP. Moreover, when fewer units are committed but the net load remains constant, the reserve margin decreases, which, as described in the previous subsection, can also increase these benefits.

The second effect of an increase in minimum run levels is that there is an increasing probability that power sinks need to be used to maintain real-time feasibility due to overgeneration, and that real-time imbalance penalties for deviating from international schedules need to be paid. This also increases the unit commitment benefits of LMP.

As these benefits are increasing in minimum run levels for the NTC-NID model, and relatively constant for the NTC-ID model, this means that the benefits of international redispatch are also greater for larger minimum run levels. This implies that, to some extent, the problems mentioned above can be solved or mitigated by international coordination on redispatch; in particular, such coupling of balancing markets decreases the use of power sinks and eliminates imbalance penalties on international flows.

4.5. Relative transmission capacity

The amount of transmission relative to the sizes of the markets might be expected to affect the benefits of LMP. To facilitate comparison with the other sensitivity analyses, we simulate the effect of changes in relative transmission capacity by decreasing or increasing all load and generation capacity by the same amount, while holding transmission constant.[5] Capacity-related costs, in particular start-up and fixed running costs, are also varied proportionally. Multiplying these parameters by x is equivalent to a decrease in transmission capacity of $1/x$.

The results are shown in Fig. 8. For this model, NTC-NID, benefits decrease in the size/load multiplier, and thus strictly increase in the transmission capacity, all else being equal. The reason is that when the available transmission capacity decreases relative to demand and the average generator size, more units close to the load in Country 2 will have to be committed, at the expense of exporting units in Country 1. In the extreme case, where the available transmission capacity is close to zero, only Country 2 units will be committed and there can be few opportunities for international redispatch. When a smaller share of demand is imported, the costs of sub-optimal commitment go down.

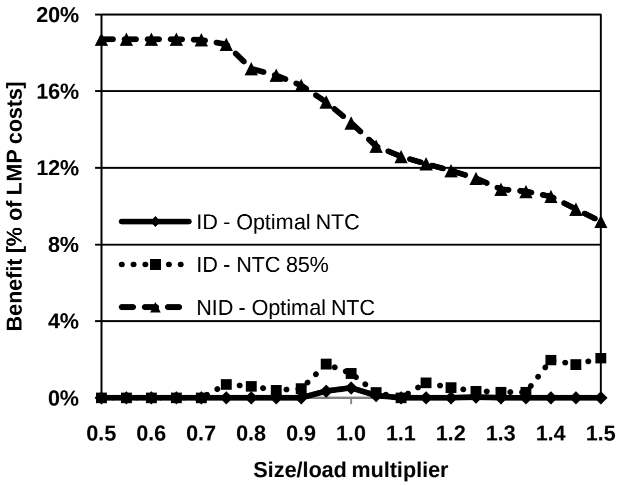

Fig. 8 Benefits as a function of generator/load size (larger values indicate smaller relative transmission capacity)

Consequently, international coordination on redispatch can mitigate a large part of the inefficiencies of NTC-based market coupling. However, even when international redispatch is possible, the unit commitment benefits of LMP can still be significant, especially when NTCs are not set optimally. However, as with most parameters, although the benefits are sensitive to the size/load

[5] If we instead varied transmission capacity, then the range of values within which the optimal NTC can lie changes. In all the other analyses, NTC can vary from 1000 MW to 2000 MW. But if, for example, the transmission capacity is halved, the optimal NTC will lie between 500 MW and 1000 MW. This complicates comparison with the other sensitivity analyses. Therefore, instead of scaling the transmission capacity up and down while keeping all other parameters constant, we scale all other parameters up and down, while keeping transmission capacity constant.

multipliers (and thus to transmission capacity), this relation is highly non-monotonic.

4.6. Load levels

Next, we test the sensitivity of the unit commitment benefits of LMP to the net loads at nodes C and D (the only nodes at which there is demand) by varying the load by +/-50%. Fig. 9 shows the results. These results look similar to those in Fig. 8 where, in addition to the net load, generator sizes are also varied, and the conclusions that can be drawn from them are qualitatively the same.

In particular, the unit commitment benefits of LMP are sensitive to load levels. When international redispatch is possible, this relationship is highly non-monotonic. Yet when international redispatch is possible, a higher load relative to the available transmission capacity almost always leads to lower benefits, for the same reasons we provided in the previous subsection. However, the variation of possible benefits is greater when load alone is varied than when load and generation are varied in proportion; thus, the effects of higher load and higher capacity appear to partially cancel each other.

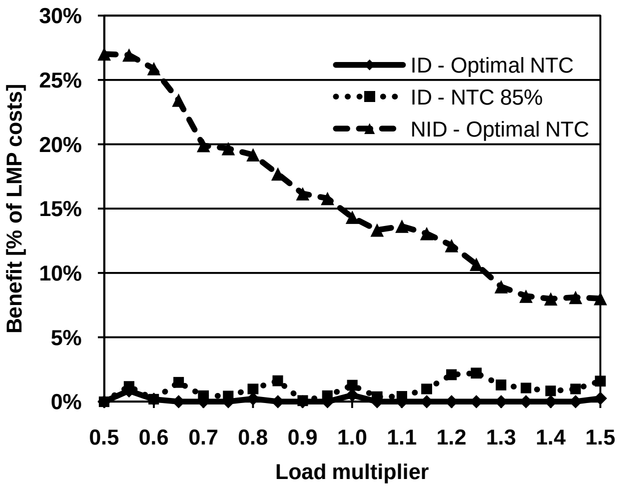

Fig. 9 Benefits as a function of load

4.7. Load asymmetry

Fig. 9 displayed the unit commitment benefits of LMP when the net loads in nodes C and D are scaled up or down simultaneously. Fig. 10 shows these benefits when instead the load at node C is multiplied by *x*, while the load at node D is multiplied by (2-*x*), where *x* is the load asymmetry multiplier, thus increasing the asymmetry in loads between the two nodes. As asymmetry increases (i.e., as *x* diverges from 1.0), transmission flows might then tend to be concentrated on one line rather than spread evenly between the two international lines. Hence, we anticipated that increasing asymmetry would inflate the benefit of considering actual transmission constraints and flows in day-ahead decisions compared to a single NTC between the two countries.

Surprisingly, however, an increase in benefits as *x* moved further from 1.0 was not observed. The unit commitment benefits of LMP peak at a load asymmetry multiplier of 0.85 for NTC-ID with optimal NTCs and NTC-NID, and at a multiplier of 1.05 for NTC-ID with an NTC of 1700 MW. On either side of these multipliers, benefits decrease. This is not only true for optimal NTCs and NTCs set at 1700 MW, but for most NTCs.

The reasons for these effects are complex, as several things change simultaneously when the load asymmetry multiplier is varied. First, although more asymmetric loads can lead to higher benefits of LMP, the load asymmetry does not increase by the same proportion in every real-time scenario, and there is always one scenario in which the load asymmetry actually decreases if load asymmetry multipliers move further away from 1. Secondly, the distribution of the total net load across the scenarios changes with the load asymmetry multiplier. In the base case, there is one scenario with a total net load of 4400 MW (scenario *HH*), two with a net load of 3200 MW (scenarios *HL* and *LH*) and one with a net load of 2000 MW (scenario *LL*). When the load asymmetry multiplier is varied, the total net load at C and D in scenarios *HH* and *LL* does not change, and neither does the average load across all scenarios. However, the loads in scenarios *HL* and *LH* do change, for example, to 2600 MW and 3800 MW, respectively, for a multiplier of 0.5. These effects interact with the other model constraints to result in the benefit curves shown in Fig. 10, which show that the benefits of LMP do not necessarily increase if loads become more asymmetric, and that they may even decrease.

The figures also show that the benefits of international redispatch vary only slightly with the load asymmetry multiplier. For instance, when NTCs are not set optimally, the additional benefit of international redispatch is relatively constant around 12.7%. In contrast, the unit commitment benefits vary considerably (on a proportional basis) over the range of *x,* from zero to 0.8% and 1.8% for the optimal NTC and 85% NTC (1700 MW) cases, respectively.

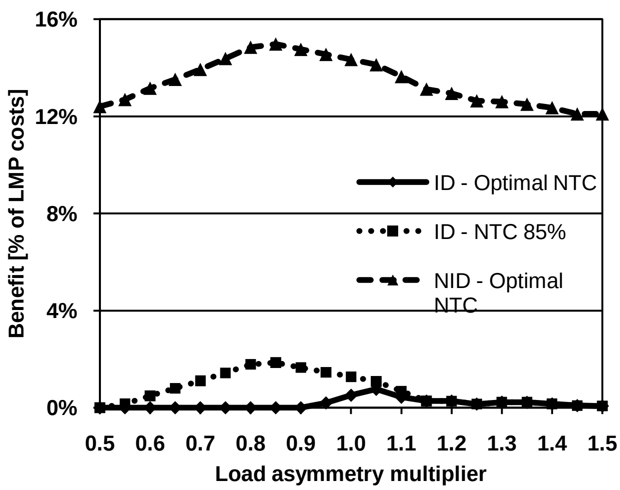

Fig. 10 Benefits as a function of load asymmetry

4.8. Load correlation

Finally, we consider the correlation in net loads at nodes C and D by changing scenario probabilities by varying parameter *a.* As noted above, this parameter can be interpreted as a correlation, where a=0 represents perfect positive correlation (when load is high at one node, it is high at the other), $a=0.25$ a situation with zero correlation, and a=0.5 perfect negative correlation (high load at one node is balanced by low load at the other). Thus, r = 1-4a is the correlation of loads in nodes C and D. Fig. 11 shows the results of a model runs with varying correlations.

From most values of *r*, the benefits increase in *r* for the NTC-ID model with optimal NTC and the NTC-NID model, although, as elsewhere, this relationship is non-monotonic. In the NTC-NID model, this relationship is less pronounced but still noticeable. These results are surprising. When the correlation is high between the net loads in nodes C and D, it is likely that the flows on the two international transmission lines will not be far apart. When this correlation decreases, there is more asymmetry in loads, and consequently the flows on the two transmission lines are more likely to diverge. In that situation, representing the four transmission constraints in the system with a single NTC is more difficult, which could lead to larger LMP benefits.

However, as in the earlier analysis where the load asymmetry was varied, this is not the only way in which the correlation can affect the benefits. Firstly, there is also a total load effect, as the variance of the total load (C+D) across scenarios increases in r. Secondly, as explained above, the non-anticipativity constraint in eq. (9) can cause the net load in the extreme scenario *HH* to constrain the commitment of generators in node A and B. The probability of this scenario is, of course, also a function of *r*.

This illustrates that it is not always straightforward to anticipate the effects of a parameter on the benefits of LMP. Several effects can interact to produce counterintuitive results.

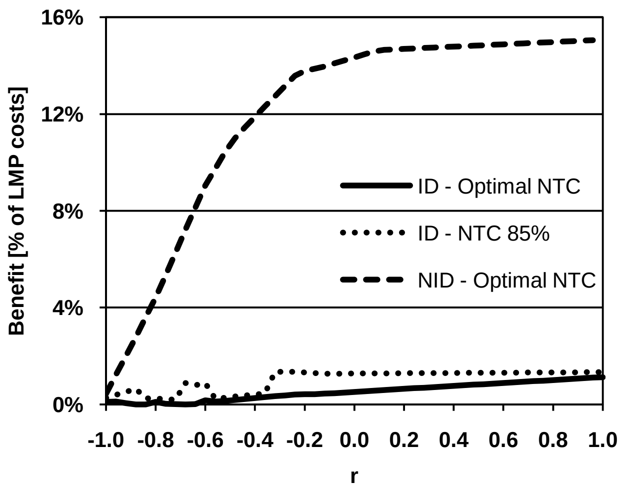

Fig. 11 Benefits as a function of load correlation

4.9. Uncertainty in net load of Country 1

In the above, we assumed the load in importing Country 2 was uncertain. As a sensitivity analysis, we made several model runs where there is also uncertainty in exporting Country 1, which could occur, e.g., if significant wind generation exists there. Table 3 shows the net loads used in this analysis. Negative net loads occur when the available wind capacity exceeds demand.

Table 3 Peak load net of wind in all scenarios (MW)

h	HH	HL	LH	HH
A	0	0	-800	-800
B	0	-800	0	-800
C	2200	2200	1800	1800
D	2200	1800	2200	1800

Unit commitment and redispatch benefits were calculated for several generator and load parameter sets under these assumptions. The general magnitude of benefits did not appreciably differ from those obtained with Country 2 uncertainty only, so we do not discuss them further.

5. Conclusions

First, coupling international day-ahead and real-time power markets using nodal pricing can lead to significant benefits compared to NTC-based market coupling only day-ahead. This has already been shown in many other studies. However, these studies do not consider the combined effect of unit commitment constraints and uncertain load and wind forecasts. Our simulations indicate that LMP can significantly improve unit commitment decisions, saving between 0% to 1% of the fuel costs of non-baseload plants, depending on the assumed parameters. This can be compared to the 0.1% of European fuel costs reported in Barth et al. (2009), the only study that is directly comparable to ours. However, unlike our analysis, that study did not consider within-country transmission, commitment of individual units, or a range of NTC values.

Secondly, full LMP-based market coupling both day-ahead and in real-time will, at least in theory, lead to the lowest costs. However, international coordination of balancing while respecting transmission constraints can provide significant benefits even if unit commitment decisions consider only NTC constraints rather than the full network. Such coordination would allow adaptation of power schedules between markets to depend on real-time load and wind scenarios and would encourage trade. This supports the conclusions of Vandezande et al. (2009). In our system, the benefits of international redispatch are at least an order of magnitude greater than the unit commitment benefits of LMP under most assumptions.

Finally, although both benefits can be significant, their magnitudes greatly depend on the exact load, generation, and transmission characteristics of the electricity markets. Generator sizes, demand levels at the various nodes, installed transmission capacity, load asymmetry and load correlation can all influence these benefits, and a small change in one of these parameters can result in significant increases or decreases, especially for unit commitment benefits. These effects are often non-monotonic, and are unlikely to be generalisable; thus, the benefits for specific systems need to be estimated by using parameters appropriate for those systems, considering the variation of loads and other parameters over the year. For our test systems, at their largest, benefits can amount to more than 25% of optimal production costs for non-baseload plants when international redispatch is not possible, and more than 2% when it is, although they are more typically around 8% and 0.8%, respectively.

Although our numerical results cannot therefore be viewed as definitive statements of the effect of various parameters, some trends are evident. When international redispatch is possible, smaller generators, higher minimum run levels and more symmetric, and positively correlated loads at different locations (net of wind) usually lead to higher benefits. When international redispatch is not possible, the effects of parameter choices often have a pronounced trend. In that case, smaller generators, higher minimum run levels, larger transmission capacities, and loads that are lower, more symmetric or positively correlated generally result in higher benefits. In both cases, continuous approximations of binary commitment variables can significantly overstate the unit commitment benefits of LMP-based market coupling for small systems.

The results are summarised in Table 4, which lists the range of benefits across the sampled range of parameters. This indicates how important these parameters are in determining the benefits of LMP and coordinated balancing. (For model NTC-NID, there is no separate column for the 85% NTC assumption, as its results are in most cases the same as the optimal NTC.)

We note, however, that the estimated benefits of LMP and international redispatch may be overstated for two reasons. First, even if operators run day-ahead markets considering only NTC values between markets, generation owners may alter their unit commitment if they recognize that cost savings are possible once real-time arrives. In particular, if those owners are forward-looking, anticipating the effect of imposing network constraints upon the real-time market, and there are no restrictions on international redispatch, they might self-commit units subject to the actual network constraints rather just the NTC. This could lower the benefits of LMP, especially in a simple network we considered. However, as networks get larger or more complex, this will be more difficult, as more information is needed in order to self-commit optimally
Secondly, we have analysed a relatively small system and, to determine the unit commitment and international redispatch benefits of LMP without distortion from other market failures, we have not included some market features currently observed in European markets. In particular, we have not included any so-called “N-1” security constraints due to possible equipment outages. Their inclusion could change the results. Larger systems should be analysed in future research using stochastic unit commitment formulations that include such security constraints.

Table 4 Results overview (benefit ranges across simulations as % of system costs under LMP)

	Benefits of LMP (No international redispatch)[a]	Unit commitment benefits of LMP[b]		LMP benefits from international redispatch (Optimal NTC)[c]
		With international redispatch (Optimal NTC)	With international redispatch @85% NTC	
Generator size and total capacity	Higher for large generators (5.5-16.88%)	No clear pattern (0-0.59%)	No clear pattern, but highest for large generators (0-2.53%)	No clear pattern (5.50-16.49%)
Generator size, fixed total capacity	Higher for smaller generators	Higher for smaller generators	Higher for smaller generators	No clear pattern
Minimum run levels	Higher for higher minimum run levels (7.67-20.59%)	Relatively constant, but lower for very high min run levels (0-0.60%)	Generally higher for higher min run levels, but lower for very high min run levels (0.12-1.81%)	Higher for higher minimum run levels (6.67-20.56%)
Transmission	Higher for larger transmission capacity (9.20-18.71%)	No clear pattern (0-0.51%)	No clear pattern (0-2.07%)	Higher for larger transmission capacity (7.14-18.71%)
Load levels	Higher for lower loads (8.00-27.03)	No clear pattern (0-0.84%)	No clear pattern (0-2.22%)	Higher for lower loads (6.69-27.03%)
Load asymmetry	Higher for more symmetric loads (12.80-14.98%)	Constant for many asymmetry levels, but generally higher for more symmetric loads (0-0.76%)	Higher for more symmetric loads (0-1.86%)	Relatively constant (12.01-14.98)
Load correlation	Higher for more positively correlated loads (0.43-15.07%)	Higher for more positively correlated loads (0-1.13%)	Generally higher for more positively correlated loads, but no clear pattern for high negative correlations (0.20-1..35%)	Higher for more positively correlated loads (0.34-14.06%)

a. Difference in total system costs (19) between models NTC-NID (Optimal NTC) and LMP, divided by (19) for model LMP. (Results for NTC-NID at 85% of thermal capacity not appreciably different.)
b. Difference in (19) between models NTC-ID and LMP, divided by (19) for model LMP.
c. Difference in (19) between models NTC-NID (Optimal NTC) and LMP, divided by (19) for model LMP.

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▪ Appendix – Results for all NTCs

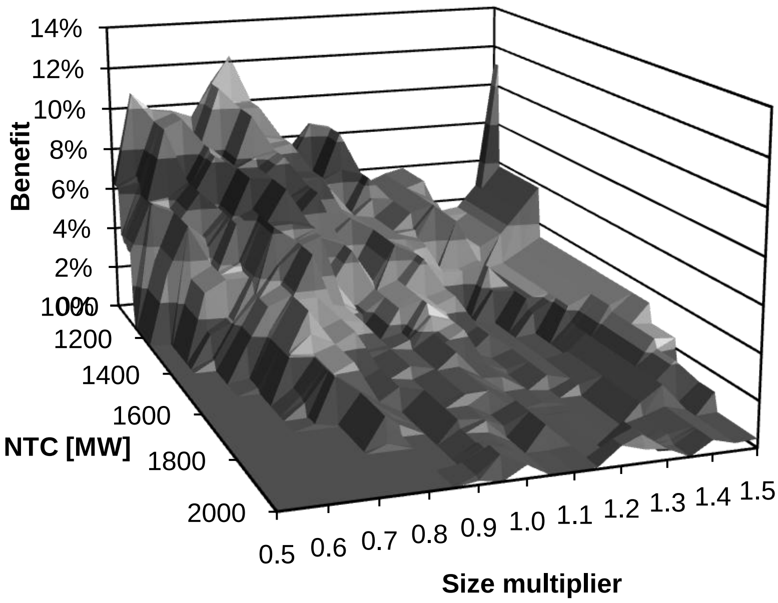

Figure A1 – Benefits as a function of generator size (NTC-ID)

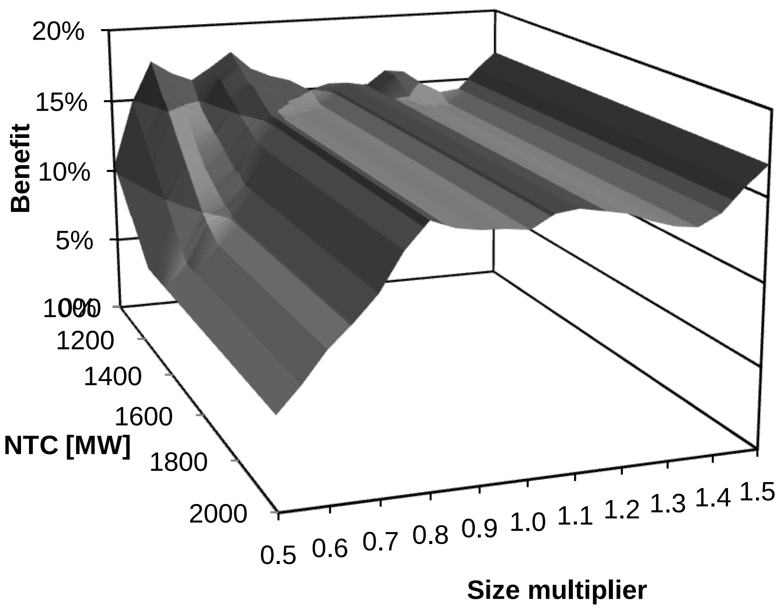

Figure A2 – Benefits as a function of generator size (NTC-NID)

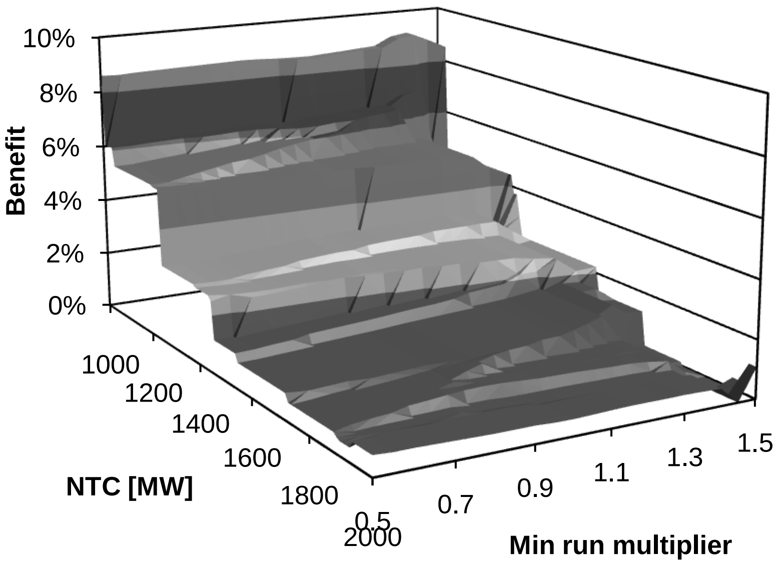

Figure A3 – Benefits as a function of minimum run levels (NTC-ID)

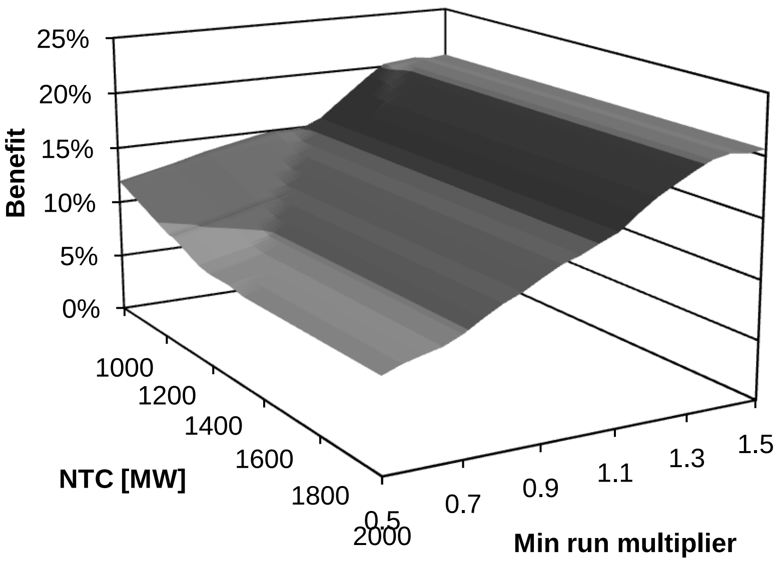

Figure A4 – Benefits as a function of minimum run levels (NTC-NID)

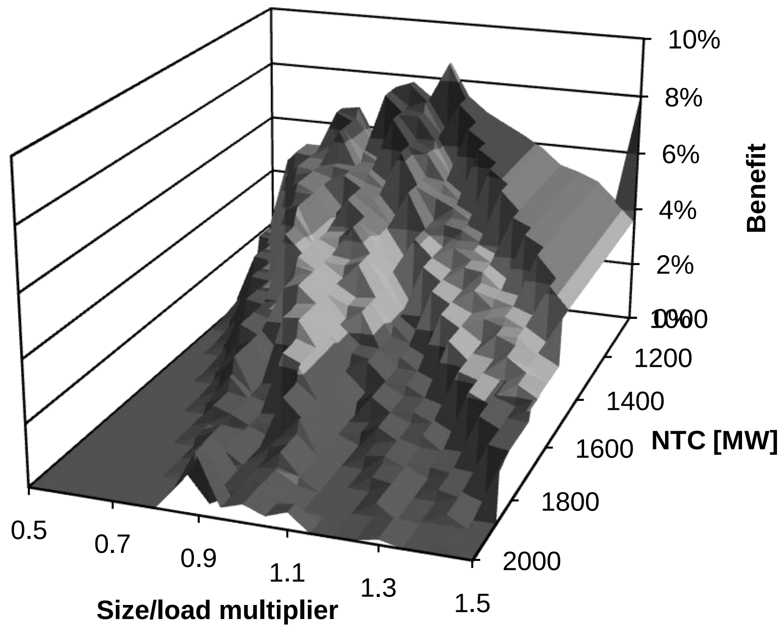

Figure A5 – Benefits as a function of generator size and load / transmission capacity (NTC-ID)

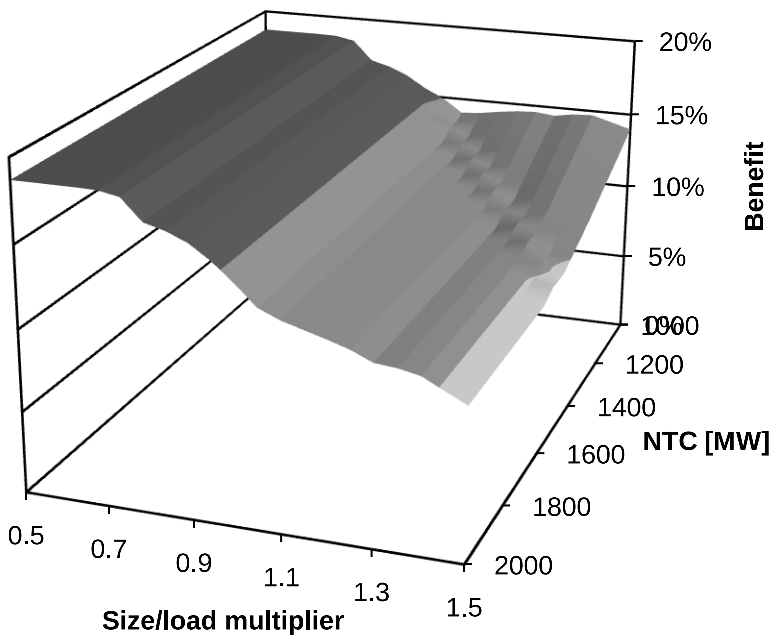

Figure A6 – Benefits as a function of generator size and load / transmission capacity (NTC-NID)

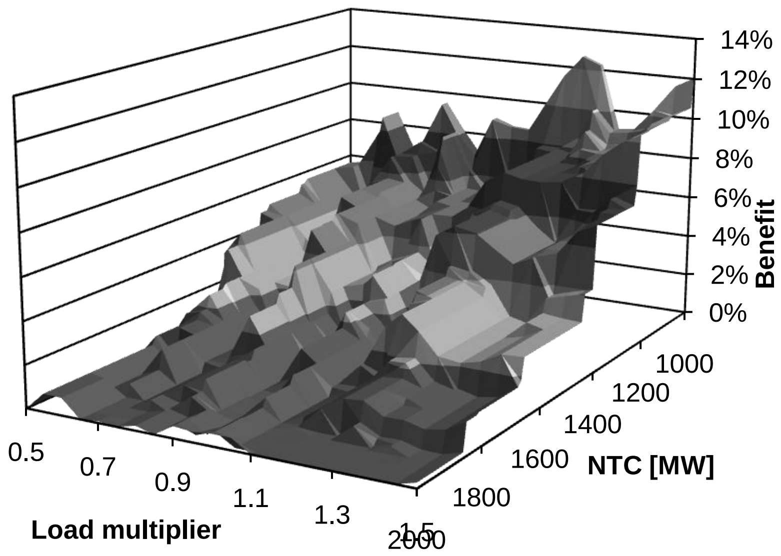

Figure A7 – Benefits as a function of load levels (NTC-ID)

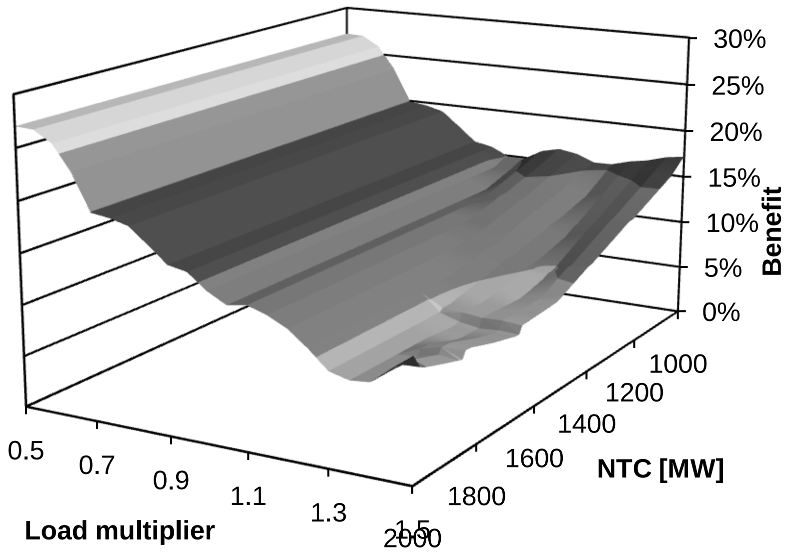

Figure A8 – Benefits as a function of load levels (NTC-NID)

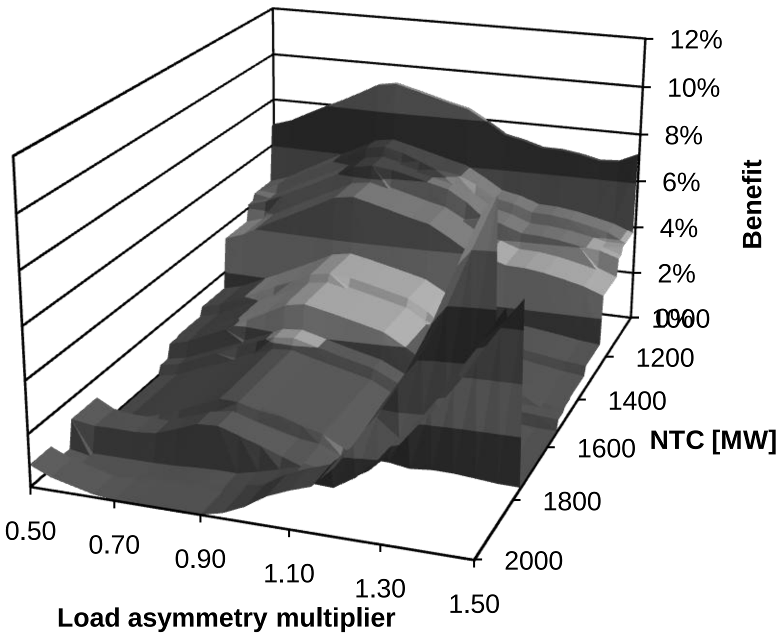

Figure A9 – Benefits as a function of load asymmetry (NTC-ID)

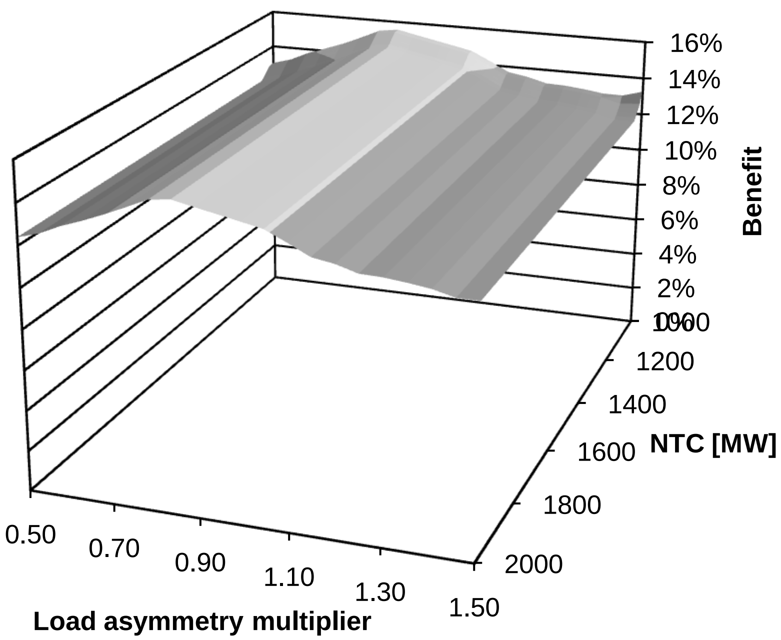

Figure A10 – Benefits as a function of load asymmetry (NTC-NID)

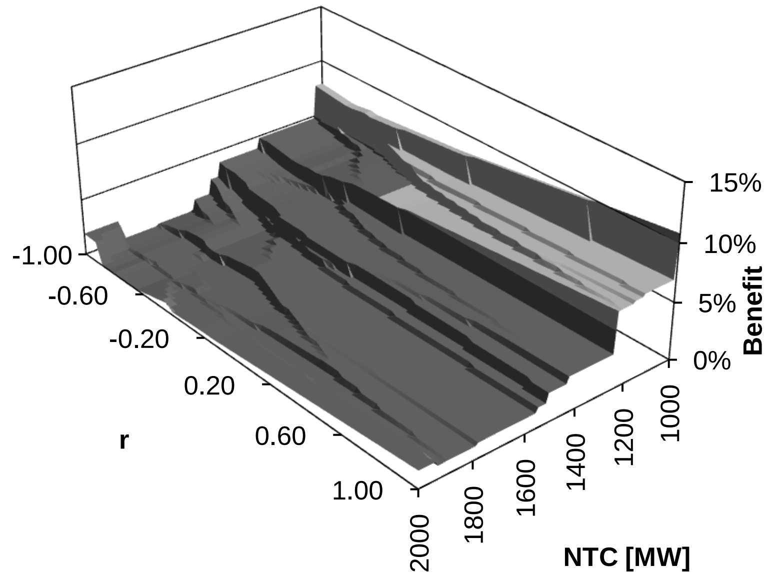

Figure A11 – Benefits as a function of load correlation (NTC-ID)

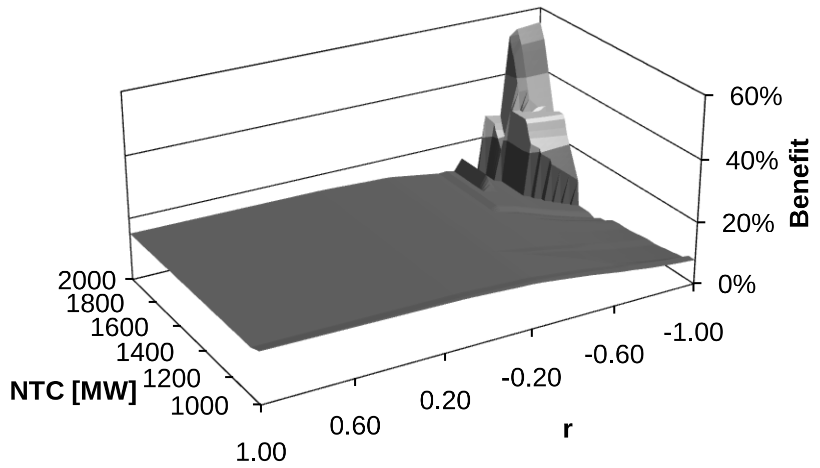

Figure A12 – Benefits as a function of load correlation (NTC-NID)
Note: rotated from A11