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Development Scenarios for the Electricity Sector

National Policies versus Regional Coordination

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Development Scenarios for the Electricity Sector - National Policies versus Regional Coordination

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Abstract

European and national climate and energy policies have fostered the development of renewable generation capacities in Europe. However political, economic, and social circumstances vary between countries. This is the case for public pressure to phase-out nuclear power and to consider other externalities, for technical potentials of renewable sources, and today's national share of conventional technologies as well as already existing renewable generation capacity. On the other hand, the progress in the development of the Internal Energy Market in Europe increased the level of interdependency of national electricity sectors.
In this context, this paper discusses the impact of regional coordination focusing on three fields of electricity infrastructure development: the expansion of renewable energy sources, the deveopment of cross-border transmission capacities, and the provision of conventional backup capacities. The results indicate benefits of coordination in the electricity system development in the central European region. Depending on the actual coordination dimensions the countries' welfare can be affected positively or negatively. The results not only motivate further research on how to succeed on the way towards a low-carbon economy but also highlight the importance of coordination to foster regional investment planning.

Keywords: Regional coordination, renewable energy investments.

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1 Introduction

Before the European market liberalization, nationally motivated developments on member state level have dominated infrastructure investments in the electricity sector. Political preferences as well as available natural ressources resulted in national differences mostly in terms of generation portfolios. The implementation of the Internal Energy Market (IEM) has improved market integration and cross-border coordination in system operation. It also reveals price differences between national markets indicating structural differences in the short-run marginal costs of the power plant portfolios. The national electricity prices in liberalized markets provide price signals for investments in generation capacity for each country or indicate insufficient cross-border capacity for trading to eliminate price differences.

Even though integration and coordination of market operation has improved the coordination in the joint planning of transmission and generation investment remains insufficient. The main reasons for this insufficiency are national differences on a political level. While the German and Swiss government have decided to retreat from nuclear power, the French power generation portfolio will rely on this generation technology in the next decades. Additionally, different speeds and strategies for carbon emission reduction can be observed. The diverse subsidy schemes in Europe are a prominent example.

Already today coordination on an European level takes place for example with the EU emissions trading system (EU ETS). However, investments in both generation and transmission infrastructure still are also subject to national considerations which leads to deviations from the welfare optimal system development. Therefore the question arises if these challenges can be overcome when coordination concerning investment strategies between countries takes place.

Investment decisions in generation capacities are influenced by national objectives, even these national plans might not be as cost efficient as a regional planning (ECF, 2011). This is acknowledged by Unteutsch & Lindenberger (2014), who also state that especially the expansion of renewable energy sources (RES) underlies national plans. The study shows that a coordinated strategy in the development of renewable energies achieves efficiency gains and leads to significant savings in system costs.

Besides generation capacities, cross-border transmission capacity is the second core area of electricity infrastructure. Buijs & Belmans (2012) point out that today still national network development plans based on national strategies dominate investment among the European TSOs. However, Saguan & Meeus (2014) found out, that there is a significant cost reduction potential in regional transmission planning on the way to achieve the renewable energy targets.

In this paper we take a closer look on impacts of national and regional orientated investment strategies on the electricity system development on an infrastructure level. In contrast to Unteutsch & Lindenberger (2014) and Saguan & Meeus (2014), we consider coordination concerning three different dimensions: the investments in renewable energy sources, the cross-border transmission grid and conventional backup capacities. The aim of this paper is to answer the question on which of these three dimensions coordination is most valuable. Furthermore we analyze the welfare distributions among the countries depending on national endowments concerning electricity systems.

Hirschhausen (2012) states three stylized scenarios for the European electricity system development. Beside the scenarios *national* and *EU-wide*, he proposes a *regional* scenario where a decentralized integration of national energy markets based on multilateral contracting is assume. This paper seizes the idea of a regional coordination as it seems to be an approach which guarantees an adequate level of flexibility for stakeholders and may have the potential to lower transaction costs significantly compared to an EU-wide approach. We apply the concept of a *regional* coordination on the central south European region including Switzerland, Austria, Germany, France and Italy. This region provides an already highly integrated electricity infrastructure network. Additionally, Switzerland and Austria have great potential to generate big parts of their domestic demand with hydro and storage hydro power plants and may play a major role in facilitating an efficient use of green fluctuating electricity in this region (ENTSO-E, 2012).

As a starting point, we provide a description of the mathematical formulation of the optimization problem. Section 3 summarizes the used data to apply the model on Switzerland and its neigbours. Results and interpretations are presented in section 4, leading to the conclusion that coordination on different investment dimensions is always benefitial for the whole region, but not not for each member state over the time horizon.

2 Methodology

The bottom-up investment model presented in this work determines the welfare maximizing development of an electricity sector composed of national markets over the course of several investment periods. The reference scenario (*no coordination*) assumes a system-wide social planner restricted by additional constraints to reflect nationally motivated energy policies. The constraints are on national investment levels in renewable and conventional power plants as well as on the cost parameter of cross-border transmission capacity. The value of regional coordination is quantified by relaxing one or a combination of these constraints.

2.1 Basic model formulation

A social planner maximizes the joint welfare of all national electricity sectors. The reference scenario with additional constraints for nationally motivated energy policies is discussed in section 3.2. The consecutive formulation states the full-coordination scenario.

The quadratic objective function (1) maximizes total annual system welfare consisting of the welfare in the day-ahead market dispatch minus annualized investment costs for several consecutive investment periods (y).[3] Future periods are discounted with an annual social discount rate (δ). The welfare of the market dispatch consists of consumer, producer, and network congestion rents which are quantified by the integral on the inverse demand function ($p(q) = a + mq$) minus the variable generation costs for all hours (t), weeks (w), and all network nodes (n) for every investment period.[4] Investments start in the second investment period. The costs for building new generation capacity ($c.cap$) and transmission capacity ($c.line$) are annualized with assumptions on investment costs, technical lifetime, and the social discount rate. The annualized investment costs have to be paid in every consecutive period starting in the period of the investment.[5]

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[3] The approach abstracts from uncertainty, the provision of reserve power, and the interaction between the district heat and the power market. The variable generation costs include beside the costs for operation and maintenance also costs for fuels and CO_2 emissions. They are scaled with a factor (yh) to one year as we do not model all 8760 hours of one due to numerical limitations.

[4] In the following single network nodes are referred to as individual countries. The model is applied to a simplified setting with national price zones.

[5] The time frame of the model does not exceed the technical lifetime of any investments. Therefore, investments remain in operation for the entire time scope of the model and the shutdown of new investments can be neglected in the model formulation.

$$\max wf = \sum_{y\in Y}\Bigg(\Bigg(\Big(\sum_{n\in N}\sum_{w\in W}\sum_{t\in T}\Big(a_{n,w,t,y}q_{n,w,t,y} + \frac{1}{2}m_{n,w,t,y}q_{n,w,t,y}^2 - \sum_{s\in S}MC_{s,y}g_{n,s,w,t,y}\Big)yh - \sum_{yy\leq y}\Big(\sum_{n\in N}\sum_{s\in S}\big(b.cap_{n,s,yy}c.cap_{s,yy}\big) + \sum_{l\in L}\big(\mathrm{b.line}_{l,yy}c.line_{l,yy}\big)\Big)\Bigg)\frac{1}{(1+\delta)^{(y-y_0)}}\Bigg) \quad (1)$$

The capacity constraint (2) limits generation output in the first period to the initial power plant capacity ($a.cap$). In consecutive periods the initial capacity is reduced by exogenous assumptions on the retirement of power plants ($d.cap$). New power plant capacity is available in the period the investment takes place and all consecutive periods. The availability of power plants varies over the course of a year, defined in the hourly availability factor (av).

Pumped storage power plants are separated in generation ($pspG$) and pumping ($pspD$) mode (3/4). The energy content of the storage is restricted by an inter-hourly constraint (5) and limited to a maximum storage level (6) which is correlated to the capacity with a linear factor (sz). The DC load flow approach (Schweppe et al., 1988) and the maximum line capacity constrain allow bi-directional network flows (7). The voltage angle (θ) is fixed to zero for one slack bus (8). Constraint (9) balances supply, demand, and network exchange for every node and hour.

$$g_{n,s,w,t,y} \leq \left(a.cap_{n,s,y} + \sum_{yy\leq y}\left(b.cap_{n,s,y} - d.cap_{n,s,y}\right)\right)av_{n,s,w,t} \qquad \forall\, n, s/\{psp\}, w, t, y \quad (2)$$

$$pspG_{n,w,t,y} \leq a.cap_{n,\{psp\},y} + \sum_{yy\leq y}\left(b.cap_{n,\{psp\},y} - d.cap_{n,\{psp\},y}\right) \qquad \forall n, w, t, y \quad (3)$$

$$pspD_{n,w,t,y} \leq a.cap_{n,\{psp\},y} + \sum_{yy \leq y}\left(b.cap_{n,\{psp\},y} - d.cap_{n,\{psp\},y}\right) \qquad \forall n,w,t,y \qquad (4)$$

$$level_{n,w,t,y} + pspD_{n,w,t,y}PspEff = level_{n,w,t-1,y} - pspG_{n,w,t,y} \qquad \forall n,w,t,y \qquad (5)$$

$$level_{n,w,t,y} \leq \left(a.cap_{n,\{psp\},t,y} + \sum_{yy \leq y}\left(b.cap_{n,\{psp\},y} - d.cap_{n,\{psp\},y}\right)\right)sz \qquad \forall n,w,t,y \qquad (6)$$

$$\left|\sum_{n \in N}\left(H_{l,n} \cdot \theta_{n,w,t,y}\right)\right| \leq a.line_{l} + \sum_{yy \leq y} b.line_{l,yy} \qquad \forall n,w,t,y \qquad (7)$$

$$\delta_{\{CH\},w,t,y} = 0 \qquad \forall w,t,y \qquad (8)$$

$$\sum_{s/\{psp\}} g_{n,s,w,t,y} + pspG_{n,w,t,y} - pspD_{n,w,t,y} - q_{n,w,t,y} + \sum_{nn \in N}\left(B_{n,nn}\theta_{nn,w,t,y}\right) = 0 \qquad \forall n,w,t,y \qquad (9)$$

The model is a quadratically constrained program (QCP) with a quadratic term in the objective function and linear constraints. Having a convex solution space, the model is solved in GAMS (General Algebraic Modeling System) using the commercial solver CPLEX.

2.2 Scenarios of regional coordination

Investments in infrastructure are often subject to national considerations due to national incentives to diverge from the optimal development of system welfare. In the following, three aspects are highlighted:

1) *Renewables*: On top of the reduction target in CO_2 emissions with a system-wide CO_2 price additional national legislation with national RES targets exists. The case of national renewable targets is enforced with an additional constraint (10) which requires a minimum level of the realized renewable generation potential for every node;

$$\sum_r \sum_w \sum_t \left(a\_cap_{n,r,y} \cdot av_{n,r,w,t}\right) yh \geq r.target_{n,y} \qquad \forall n, y \qquad (10)$$

2) *Grid expansion*: Coordinated transmission capacity expansion with lower investment costs vs. national planning of the transmission capacity expansion assuming five times higher costs for grid infrastructure.

3) *Backup Capacity*: Regional provision of backup capacity vs. the requirement of national backup capacity of conventional power plants. The hourly national load and renewable generation patterns are not perfectly correlated. This causes the maximum residual load for the entire system to be lower than the sum of the residual load hours of the individual countries. Therefore, regional coordination to cover peak load reduces the amount of required backup capacity. The coordination scenario only requires peak load coverage at the system level. National sector planning can include national capacity requirements. The non-coordination scenario for capacity includes a constraint (11) that enforces the possibility of national peak load coverage.

$$\sum_c \left(a.cap_{n,c,y} + \sum_{yy \leq y}\left(b.cap_{n,c,y} - d.cap_{n,c,y}\right)\right) av_{n,c,w,t} \geq q_{n,w,t,y} - \sum_r g_{n,r,w,t,y} \qquad \forall n, y \qquad (11)$$

To be able to evaluate the distributional effects of these different types of coordination, eight different scenarios are defined, where coordination takes place in all three, two, one or no dimensions. The scenario *no coordination* is the reference scenario and includes only national policies. All other combinations are compared with this scenario to analyze the effects of coordination in the model results. The counterpart of the *no coordination* scenario is the *full coordination* scenario, which assumes regional coordination on all dimensions. The remaining scenarios are named after the dimensions where coordination is implemented. The scenario *coordination in renewables and grid expansion* represents for example a setting where national renewable policies are neglected and lower investment costs for transmission capacity expansion are assumed. Since no coordination concerning backup capacity takes place, each country needs to provide sufficient national backup capacity. The results are available, both, on regional and national level.

3 Input Data: Application to Switzerland and its Neighboring Countries

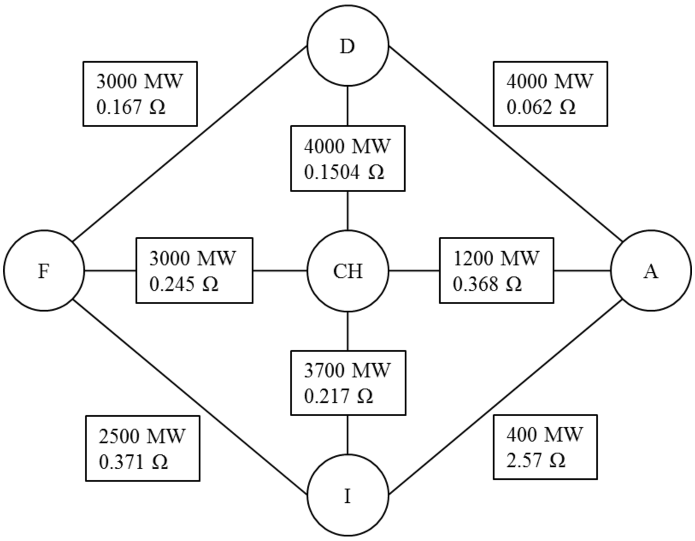
The endowments and assumptions on the prospective development of the national electricity systems determine the role of each country in the different scenarios. The geographical center of the region is Switzerland which has large shares of hydropower generation (run-of-river and storage) combined with nuclear power. The country has plans to phase out nuclear by 2034. Austria's electricity supply is also dominated by hydropower. Generation capacity in Germany still has a relatively large stock on conventional power plants. But the electricity sector is undergoing a transformation process including a nuclear phase out by 2022 and ambitious RES expansion targets. The French power plant portfolio is characterized by a large share of nuclear generation capacity which is to be reduced with increasing RES shares. Italy is the country with the largest capacity in modern gas-fired power plants.

The model application uses stylized sector and market data for the different scenarios. The analysis is restricted to only one possible development of market prices and restricted by the simplifications in the model setup (e.g. no consideration of uncertainty and flexibility). This has to be considered in the discussion of the results.

3.1 Electricity sector data for the initial model period

The model formulation of the different scenarios is applied to the electricity markets of Switzerland, Austria, Germany, France, and Italy. The five national markets are represented in an aggregation with one node per country (Figure 1).[6] For the transmission network assumptions are made on the initial exchange capacities and the aggregated line reactance between two countries.

Figure 1: Spatial aggregation with exchange capacity and aggregated line reactance



Source: Own illustration with reactances (Purchala, 2005) and stylized values for exchange capacities.

As for the time resolution, the day-ahead market is modelled for four weeks per year in all investment periods. The weeks represent the four seasons using data on hourly demand levels and market prices as well as seasonal/hourly availability factors for conventional/renewable generation capacity.

Every country has an hourly electricity demand function calculated by the historic reference demand (ENTSO-E, 2013), the corresponding day-ahead market price (EEX, 2013a; GME, 2014), and a price elasticity of -0.25. Initial generation capacity is distinguished in 11

[6] The described methodology can be applied to nodal electricity systems. For numerical reasons, this representation simplifies the spatial character of national systems to evaluate the impact of coordination compared to national policies.

different technologies. The six conventional technologies include nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), gas peak capacity (GT), and oil peak capacity.[7] Renewable technologies are differentiated in hydro run-of-river plants, biomass, wind, and photovoltaics (PV). In addition, hydro pumped storage is considered with inter-temporal constraints within one week. Table 1 states the initial power plant portfolio for the first model period (2015).

Assumptions on conventional power plants include seasonal availability factors of 90% in the winter, 80% in spring and autumn, and 70% in the summer week. For wind and PV, hourly factors are derived from the historic feed-in in the four weeks adjusted to equal total annual wind output for all countries[8] and varying annual output levels for PV (50Hertz, 2013; Amprion, 2013; RTE 2013; Tennet, 2013; Terna, 2013; TransnetBW, 2013).[9] Thereby, the model has an incentive to distribute wind on all countries as its output is not perfectly correlated. Distinguishing the output levels for the national aggregation would require a deeper analysis of national potentials. The differentiation in annual output for PV increases the levels in southern countries.

[7] We do not consider carbon capture transport and storage (CCTS) in this study.

[8] The different amounts of full load hours per year in each season are: January-March 600 FLH, April-June 400 FLH, July-September 300 FLH, and October-December 400 FLH (EEX, 2013b).

[9] The average photovoltaic generation availability in every season is multiplied by 1.1 for Austria and Switzerland, 1.2 for France and 1.5 for Italy.

For the development of the generation portfolio, today's capacities expire at the end of their technical lifetime. Moreover, new investments in nuclear, oil and lignite[10] capacity are not allowed. All future costs and rents are discounted with an annual social discount rate of 4%.

Table 1: Initial power plant portfolio

[GW]	CH	AT	DE	FR	IT
Nuclear	3.2	0.0	12.1	62.6	0.0
Lignite	0.0	0.0	21.0	0.0	0.0
Hard coal	0.0	1.6	27.2	6.2	10.5
CCGT	0.1	2.6	10.0	3.4	32.0
Gas turbine	0.2	1.5	14.0	4.0	14.1
Oil turbine	0.1	1.0	3.8	7.6	11.2
Hydro	11.7	9.2	4.4	17.8	13.1
Biomass	0.3	0.3	2.1	0.7	1.1
Wind	0.1	2.0	40.8	9.7	10.0
Photovoltaic	0.1	0.5	41.5	4.7	21.2
PSP	3.4	2.0	6.5	4.5	5.7

Source: Own compilation estimating the installed capacities in 2015.

3.2 Assumptions on the development of price parameters in the electricity sectors

The dynamic setting with investment periods in steps of five years requires assumptions on future price data for investment cost, fuel prices of fossil resources, and CO_2 emission allowances. The investment costs (Egerer et al., 2014) are recalculated to annualized parameters using the technical lifetime and the social discount factor Fuel prices for the initial model period are 2.0 EUR/MWh_{th} for lignite, 3.0 EUR/MWh_{th} for uranium, 10.1 EUR/MWh_{th}

[10] Investments in lignite capacity are only allowed in Germany.

for hard coal and 22.9 EUR/MWh$_{th}$ for natural gas. The initial price ratio between natural gas and coal increases from the factor 2.3 to 2.8 in 2040. The price path for CO_2 allowances follows the renewable scenario of the Energy Roadmap 2050 (EC, 2011) reaching 35 EUR/ton CO_2 in 2030 and 92 EUR/ton CO_2 in 2040.

3.3 Scenario parameters for national and regional coordination scenarios

The different options for national and regional coordination scenarios are approached by additional model constraints with additional parameters:

- *Renewables* : The reference scenario enforeces a constraint on renewable generation targets on country level.[11] The renewable share of national demand is 80% for Germany and Italy and 90% for Switzerland and Austria. France has only a RES target of 50% due to the remaining nuclear capacities. If coordination concerning renewables takes place, national expansion targets are neglected.
- *Grid Expansion:* A sensitivity of five times higher investment cost for cross-border transmission capacity is tested in the national transmission scenario.[12]
- *Backup Capacity:* Third, the capacity covering peak does not require additional parameters.

4 Results

The model provides results for eight different scenarios, combining the different coordination levels. The results are divided in two parts in order to identify the effects of coordination. In a first step we determine the value of coordination on regional level and its impacts on system

[11] The table with exact data is provided in the Appendix.

[12] The parameter is set to 200,000 EUR/MW for every line in the regional coordination scenario. The number calculates by a length of 100km, investment costs of 1.4 mn EUR/km, 1,400 MW in line rating (50Hertz et.al. 2013), and a factor of two to account for the meshed character of the network which requires additional investments.

investments in generation and transmission capacities. Second, we discuss the distributional effects of regional coordination on a national level based on specific local conditions.

4.1 Effects of regional coordination on system development

The main statement of the model results which is not surprising is that regional welfare increases with coordination. The *full coordination* scenario is superior to all other scenarios and provides a welfare increase in the present value of 23 bn. EUR over 26 years compared to the reference scenario. Also, in all other scenarios with coordination in at least one dimension regional welfare is higher than in the scenario *no coordination.* This indicates that coordination on any level is beneficial on regional level.

Table 2: Accumulated system welfare difference compared to the scenario *no coordination*

Scenario	**Welfare gains [bn. EUR]**
Coordination in backup capacity	4
Coordination in grid expansion	5
Coordination in grid expansion and backup capacity	10
Coordination in renewables	15
Coordination in renewables and backup capacity	18
Coordination in renewables and grid expansion	20
Full coordination	23

Source: Own calculations based on GAMS

Table 2 depicts the accumulated system welfare difference compared to the *no coordination* scenario. All scenarios neglecting national targets for renewable generation capacity lead to a larger welfare increase than all other scenarios, even compared to those where coordination takes place in the two other dimensions (coordinated interconnector capacity expansion and shared backup capacities). National policies only concerning the interconnector expansion and conventional backup capacity do not restrict the welfare development as much as national targets in the expansion of renewable energy generation capacities. Backup capacity coordination has the smallest effects on system welfare, since its accumulated system welfare is closest to the *no coordination* scenario. The impact of a coordinated grid expansion on system welfare always depends on the composition of the national power plant portfolios. The largest effects can be observed when national RES targets are realized and backup capacity is provided on a regional level at the same time. As soon as only a CO_2 price regulates emissions the effect of a coordinated grid expansion decreases.

4.2 Effects of regional coordination on national investments

The investments play a central role in this study as they are the decisive variable in the model concerning the distributional effects within the region. The long lifetime of power plants results in a duration of several decades before a complete replacement of today's generation portfolio. Thus, recent investments in power plants are still in operation at the end of the model scope. In addition to the remaining historic capacity in each investment period, national availability factors for renewables have the same effect for investments on national level in all scenarios. The difference in the generation investments result from limited market integration and related integration costs by transmission investment, national renewable targets and national back-up requirements.

First of all, the total investment costs are divided into generation capacity and transmission investment costs. Investment in generation capacity constitutes to about 99% of total investment costs. Cross-border line expansion therefore plays a minor role from an investment perspective. Still, the coordination on transmission investments (lower costs) increases welfare by 5 bn. EUR compared to the *no coordination* scenario over the time scope of the model.

The *coordination in backup capacity* scenario displays only small differences in investments compared to the *no coordination* scenario. The only country which provides significant changes in the generation capacity investment portfolio is Italy. The coordination in backup capacity lowers the investment need for gas turbines in Italy. In fact in this case, Italy does not invest in conventional capacities at all, leading to lower overall investment costs for Italy. The region, especially France with high nuclear generation capacities provides sufficient conventional backup capacities to cover residual loads. Due to high investment costs for cross-border transmission capacity no investments in the grid take place in this scenario.

The *coordination in grid* scenario leads to higher investments in the cross-border network. Especially the lines connecting Italy and Switzerland, Italy and France and Germany and France are extended. The main effect on generation is a higher PV investment level in Italy after 2020. In contrast, Germany and France see less investment in PV. This explains the investments in the Italian cross-border network, as the Italian exports steadily rise until 2040.

The *coordination in renewables* scenario (Table 3) provides crucial differences in the investment scheme compared to the other dimensions of coordination and has a much stronger shift of PV capacity investments towards the south. In terms of investment costs Germany and France benefit the most from coordination in RES. Due to a shift of RES investments towards Austria and Italy, Germany and France are able to save large amounts of investments in RES capacities. Especially France benefits as the need to invest in RES, especially PV capacity is delayed and only urgent when the carbon price jumps in the time step from 2030 to 2035. In 2020 France has 9% lower investment costs in the *coordination in renewables* scenario compared to the *no coordination* scenario, in 2040 the investment costs are 0.3% higher.When national renewable energy targets are implemented on top, total generation investment costs increase. Especially France and Germany need to invest in renewable energy sources in order to meet national targets.

Table 3: Mean accumulated national investment costs in generation capacity

	Mean investment costs	
[bn. EUR]	**National RES targets**	**Coordination in RES**
CH	25	24
AT	19	21
DE	146	121
FR	153	147
IT	77	80
Σ Total	420	392

Source: Own calculations based on GAMS

4.3 Effects of coordinated planning on national welfare

The national welfare level (Table 4) is an important indicator for national policy makers. It composes of consumer, producer, and congestion rents which are determined by the hourly national electricity prices, national production patterns, the electricity trade flows, and national investment costs.

When comparing only the scenarios where coordination takes place in one dimension, Switzerland profits the most in the scenario with coordination in backup capacity. Its welfare in this scenario is even higher than in the *full coordination* scenario. Italy provides similar scenario sensitivity and also profits the most from coordination in backup capacity. The Austrian welfare is relatively indifferent to the coordination scenarios; it benefits the most in the scenario with coordination in renewables. Germany provides the highest gains in welfare in this scenario, too. The French electricity sector benefits from any level of coordination. Again, especially coordination in renewables leads to a significant rise of welfare. All countries benefit from the full coordination scenario but only for Germany and France it is the dominant scenario out of the four ones presented. However, countries like Switzerland and Austria which are central in the model scope have to accept welfare losses.

Table 4: National welfare difference to *no coordination* scenario

[bn. EUR]	Coordination in backup capacity	Coordination in grid expansion	Coordination in renewables	Full coordination
CH	1.6	-0.2	-0.2	1.5
AT	-0.1	0.0	0.2	0.1
DE	0.2	-0.3	6.2	7.7
FR	0.2	5.8	9.1	12.8
IT	2.3	-0.4	-0.3	1.2

Source: Own calculations based on GAMS

5 Conclusion

The results of this paper do not only confirm the widely accepted view that coordination is beneficial, they also compare different dimensions of coordination. The model results see the highest potential welfare gains from neglecting national renewable policies and therefore cooperation in a regional development of renewable capacities. Benefits for coordination of transmission and back-up capacity are only half the level but their value still provides an incentive for coordination. This is the more the case, as the results suggest higher welfare gains for the combination of dimensions of coordination than for the sum of gains of individual dimensions.

Depending on the actual dimensions the welfare of individual countries can be affected positively or negatively. As individual countries favor different sets of coordination dimensions the full coordination case is not the unchallenged optimum. Individual countries could be reluctant to cooperate without additional instruments (e.g. a compensation mechanism or European regulation). Thus, the region as a whole would not be able to reach the preferable state of full regional cooperation with the highest regional welfare level.

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Appendix

Table 4: Sets and indices, parameters, variables

Symbol	**Description**	**Unit**
Sets and indices		
n, nn $\in$ N	Country	
l $\in$ L	Corss-border transmission line	
s $\in$ S	Generation technology	
R $\subset$ S	Renewable energy source generation technology	
C $\subset$ S	Conventional generation technology	
y, yy $\in$ Y	Years in steps of five years	years
w $\in$ W	Season weeks (winter, spring, summer, autumn)	week
t $\in$ T	Hours	hour
Parameters		
a	Prohibitive price	EUR/MWh
a.cap	Initial power plant capacity	MW
a.line	Initial transmission capacity	MW
av	availability factor of a generation technology	
B	Network susceptance matrix	
MC	Marginal costs	EUR/MWh
c.cap	Generation investment costs	EUR/MW
c.line	Cross-border transmission line investment costs	EUR/MW
d.cap	Retirement of power plant capacity	MW
H	Flow sensitivity matrix	
m	Slope of the inverse demand function	
PspEff	Efficiency of a pump storage power plant	
r.target	National RES generation target	MWh/a
sz	Conversion of storage size to generation capacity	MWh/MW
yh	Scale factor	
δ	Annual social discount rate	
θ	Voltage angle	
Variables		
b.cap	Built generation capacity	MW
b.line	Built transmission capacity	MW

g	Generation	MWh
level	Pump storage potential	MW
pspD	Pumping of pump storage power plants	MWh
pspG	Generation of pump storage power plants	MWh
q	Demand	MWh
wf	Present value of accumulated social welfare	EUR

Table 5: Investment costs

[EUR/kW]	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Lignite	1,500	1,500	1,500	1,500	1,500	1,500
Coal	1,800	1,800	1,800	1,800	1,800	1,800
CCGT	800	800	800	800	800	800
GT	400	400	400	400	400	400
Oil	400	400	400	400	400	400
Hydro	3,000	3,000	3,000	3,000	3,000	3,000
Biomass	2,425	2,350	2,280	2,209	2,143	2,076
Wind	1,270	1,240	1,211	1,182	1,155	1,127

Source: Egerer et al. (2014).

Table 6: National RES generation targets

[TWh/a]	**2020**	**2025**	**2030**	**2035**	**2040**
CH	42.50	45.85	49.50	53.15	56.80
AT	46.90	50.05	53.20	56.35	59.50
DE	214.50	271.00	327.50	384.00	440.50
FR	129.50	157.20	184.90	212.60	240.30
IT	88.10	134.10	180.10	226.10	272.10

Source: Calculation based on own assumptions.