A COST-BASED APPROACH TO EVALUATE FUTURE GRID STRUCTURE OPTIONS[1]

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Abstract:

In addition to striking problems in electricity grids (e.g. necessary restructuring measures due to the increased distributed deployment of renewables [1]), currently there are hardly any incentives for grid operators to undertake necessary grid infrastructure investments due to given regulatory regimes. The danger of under-investments in existing grids is growing and the security of supply can be seen as harmed (see e.g. [2]). A first step towards the derivation of future investment needs (and the necessary incentives) is to define possible future electricity supply scenarios. The central research question therefore is: Which grid structure scenarios (e.g. smart, super or hybrid grid design) in Austria are - dependent on the generation structure - possible or necessary to provide secure electricity supply. Correspondingly it needs to be evaluated, how high total system costs compared to a Business-As-Usual (BAU) Scenario evolve.

The scenario modelling starts at the current condition of peak load coverage, which is enabled by the national generation capacities (fossil & renewable) and by import capacities at cross-border transmission lines. The yearly total costs (investment, O&M costs) of generation and import capacities are furthermore calculated on the basis of generation scenarios from a recently published study [3]. For the determination of grid costs the 2006 BAU costs have been extrapolated and updated to the future. Additionally, planned transmission projects [15] as well as costs of future distribution grid investment scenarios [1] have been taken into account. Furthermore, in order to make the capacity and grid costs comparable, the generation and import capacities' costs as well as grid costs (fixed & variable costs of transmission and distribution grids) are converted to a cost indicator '€ / MW installed' related to the total capacity installed. Finally, these results are used as a basis for upper grid cost calculations (e.g. for Smart Grids) in order to be able to compete with a BAU scenario (e.g. with cable laying). Above all, a reference and two alternative scenarios will be discussed in detail within this paper.

Keywords: future grid scenarios, investment incentives, smart / super / hybrid grids

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1 Introduction

The yearly investments in the transmission and distribution grid peaked in the 1970s as demonstrated in Figure 2. Since then investments have decreased constantly. By taking into account an assumed grid assets' average lifetime of 40 years it is plausible that from now on substantial investments in the refurbishment of the Austrian electricity grids or new assets like new lines and cables may become likely.

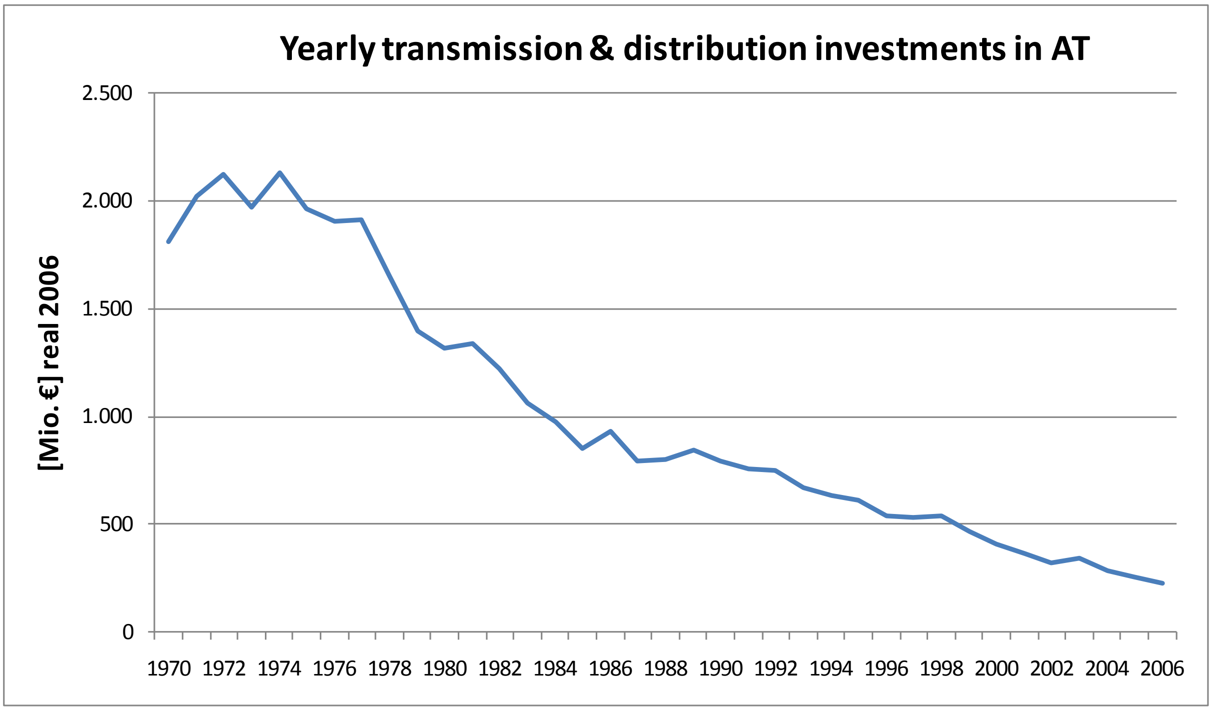

Figure 1: Historic yearly investments in the transmission and distribution grid between 1970 and 2006 in Austria (Mio. €, 2006 prices). Source: [11]

Within the context of discussions about the future energy and electricity system in Europe (see e.g. [16] or [14]), particularly taking into account an increasing integration of (distributed) renewable energy generation and solutions for a more efficient supply of the constantly rising electricity demand, experts of the electricity branch are discussing possible future structures of the electricity grid. One option, as schematically depicted in Figure 3, is to continue the today's system ('BAU' (Business-As-Usual) scenario), dominated by a passive supply and demand as well as a mainly centralised generation structure. The 'FUTURE EFFRES' or 'FUTURE CO2" scenario is an alternative electricity supply system with an increased amount of distributed and renewable generation, enhanced by Efficiency (EFF) strategies and an increased penetration of renewable generation. Additionally, Super Grid scenarios are discussed [17], which are based on the idea to overcome all cross-border bottlenecks in Europe and investments in the extension of the European compound transmission grid.

But no matter which grid scenario is discussed, it has to be answered whether alternative scenarios imply extra costs or benefits for society compared to the continuation of the past structure.

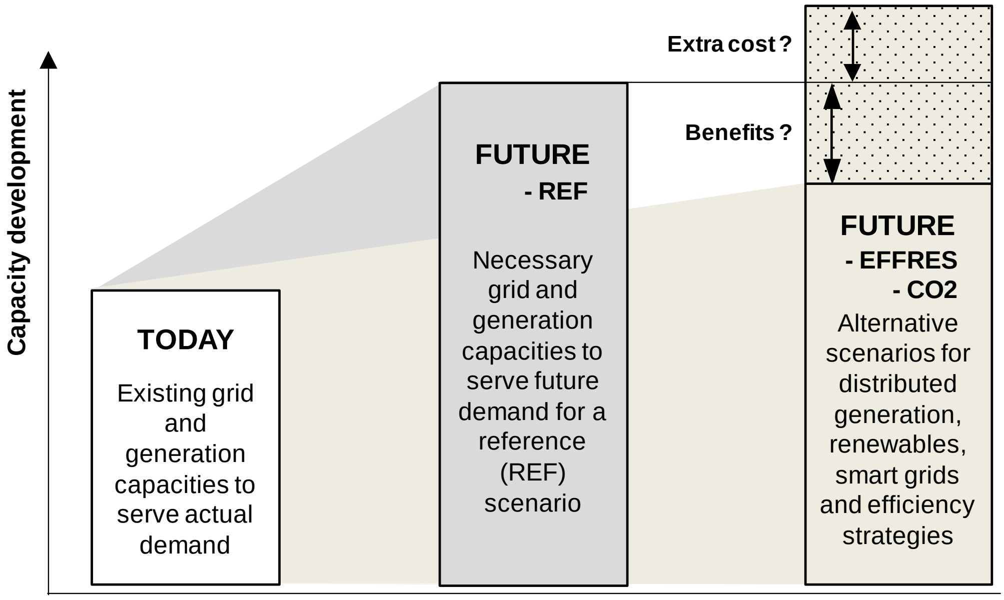

Figure 2: Possible electricity system capacity developments for a Business As Usual (BAU) and an alternative scenario (with a positive or negative Efficiency-Renewable (EFFRES) impact and a CO2 saving impact) compared to the present situation. Source: Illustration designed by [12] in accordance with [13] and [14].

In addition to that question, possible amendments or adaptations of the current regulatory regimes has to be analysed. As discussed in [8] sufficient incentives for grid operators to invest in the extension and preservation of the grid infrastructure, especially facing the challenges referred to alternative grid structures, is currently not given in many places.

A necessary first step for the derivation of the future investment needs in the electricity grid (and the identification of investment incentives) is to define possible future grid scenarios, based on the aspired future electricity generation structure. The central research question within this paper therefore is:

Which scenarios of the grid structure (as e.g. Smart Grid) in Austria are possible or necessary and how does their level of costs look like compared to a reference-Scenario?

2 Methodology and data

Within the current predominantly passive electricity supply system, peak load shifting mechanisms (such as e.g. interruptible contracts) are rarely applied and consumers are far away from broad active co-operation. Furthermore, preliminary electricity suppliers' goals in the liberalized electricity markets are to maximise electricity sales and to derive a highest possible profit situation. This includes that generation and trade of electricity is organized as such that peak demand can be met at any point of time. Therefore, peak load coverage is the starting pre-condition for the scenario modelling of this paper.

This is secured by national generation capacities (fossil and renewable) as well as by the import capacity at the cross-border transmission lines (NTC - Net Transfer Capacities). This concept is shown in Figure 2 where the generation capacities are indicated by the black part of the bars (conventional, i.e. fossil fuel fired power plants and large hydro plants) and by the green part of the bars (RES-E, i.e. renewable electricity plants including small scale hydro capacities).

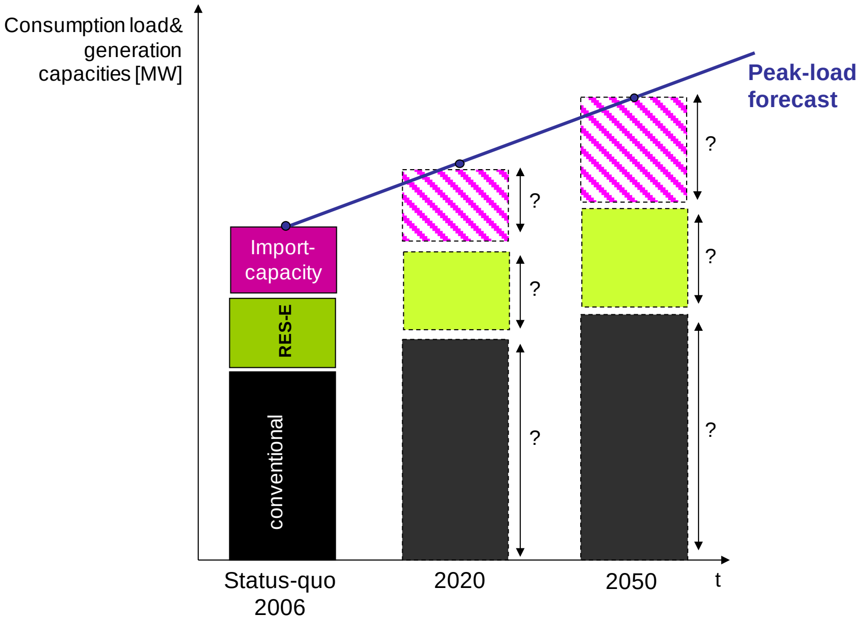

Figure 3: Schematic depiction of peak-load coverage: Principle of the scenario derivation. Own depiction.

In order to eventually meet the peak load, the gap between the blue curve (peak load forecast) and the generation capacities has to be covered by import capacity (NTC), indicated by the pink part of the bars. According to that schematic depiction, the status-quo and so the starting point for the scenario building is assembled with 2006 data. Furthermore, the question marks in Figure 2 signalise that the future scenarios (here schematically indicated for 2020 and 2050) are defined by the different composition of the single capacities. For example one scenario could be dominated by renewable power generation, i.e. the green parts of the bars (RES-E capacities) would be higher than in the status-quo whereas no additional import capacity is needed to cover peak load. Therefore, in the following section the used generation scenarios are explained in detail.

2.1 Future electricity generation scenarios

Figure 4 to Figure 6 depict the installed generation capacities of the status-quo 2006 ([4] and [21]) and of three different generation scenarios in Austria: The reference (REF) scenario, efficiency & renewable scenario (effres_support) and the CO2-support scenario (CO2_support). All three scenarios (and respective data) are taken from a recent study “Langfristige Szenarien der gesellschaftlich optimalen Stromversorgung der Zukunft”, compare [3].

Additionally for the peak load forecasts two different data sets are used: On the one hand, the published UCTE peak load forecast until 2020 is taken and extrapolated until 2050 [6]. On the other hand the historic peak load trend is extrapolated to 2050. Furthermore, the total NTC values are drawn from the etso-vista online database [5], i.e. the published values for the first Wednesday in January 2006, if not otherwise stated.

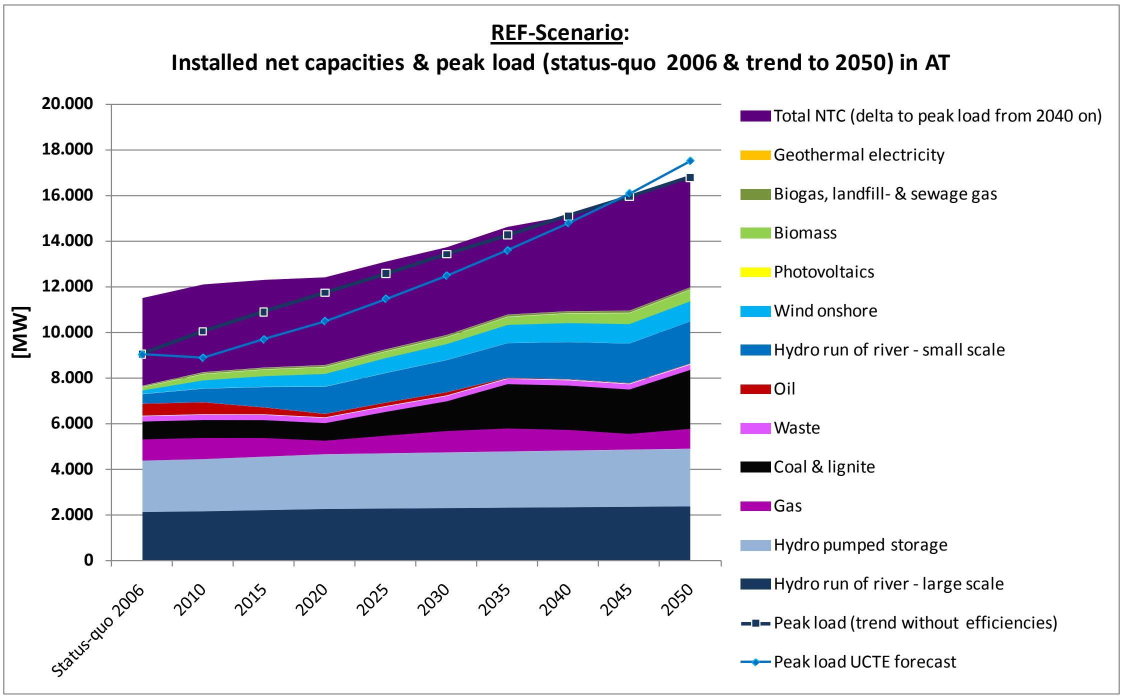

Figure 4: **Installed net capacities (generation and NTC) as well as peak load forecasts to 2050 in Austria in the REF (reference)-Scenario. Source: [3], [4], [5], [6] & own calculations.**

The reference "REF"-scenario is characterized by a positive demand increase (to 95 TWh until 2050) as well as low primary energy and CO2 prices (coal: 10 €/MWh, gas: 30 €/MWh, CO2 (constant): 15 €/tCO2, wholesale electricity: 60 €/MWh). Consequently, coal, gas but also wind power as well as small scale hydro capacities increase, but only minor additional renewable capacities are installed. This is because no subsidies for renewables are foreseen in the reference scenario. From the year 2040 onwards additional Net Transfer Capacities (NTC) have to be installed in order to meet peak load (calculated by the delta between peak load and all installed national generation capacities).

The "effres_support"-Scenario is dominated by a decreasing demand rate (70 TWh until 2050) and heavier increasing primary energy and CO2 prices (coal: 18 €/MWh, gas: 44 €/MWh, CO2: 43 €/tCO2, wholesale electricity: 92 €/MWh). Yearly € 200 million subsidies are available for new renewable power plants (excluding large scale hydro), which covers the difference of generation costs and market prices until 2050.[2] Due to decreasing demand the installation of new thermal power plants is not necessary. Highest installation rates are observed for small-scale PV (due to appropriate support schemes) and hydro power plants. Because of the same argument it is assumed, that peak load will also decrease and the UCTE forecast levels are not valid any more. Therefore, no new NTC is necessary.

[2] The costs for society for the subsidies are not stated individually, because they are accounted for by the valuation of the according generation capacities' cost.

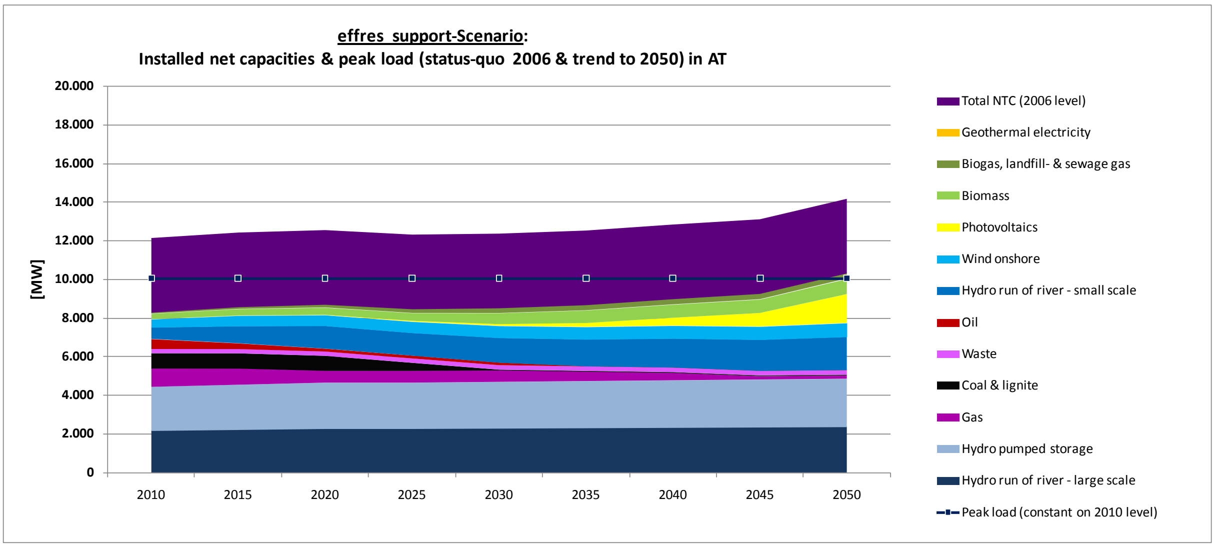

Figure 5: **Installed net capacities (generation and NTC) as well as peak load forecasts to 2050 in Austria in the <u>effres_support (efficience/renewable)-Scenario</u>. Source: [3], [4], [5], [6] & own calculations.**

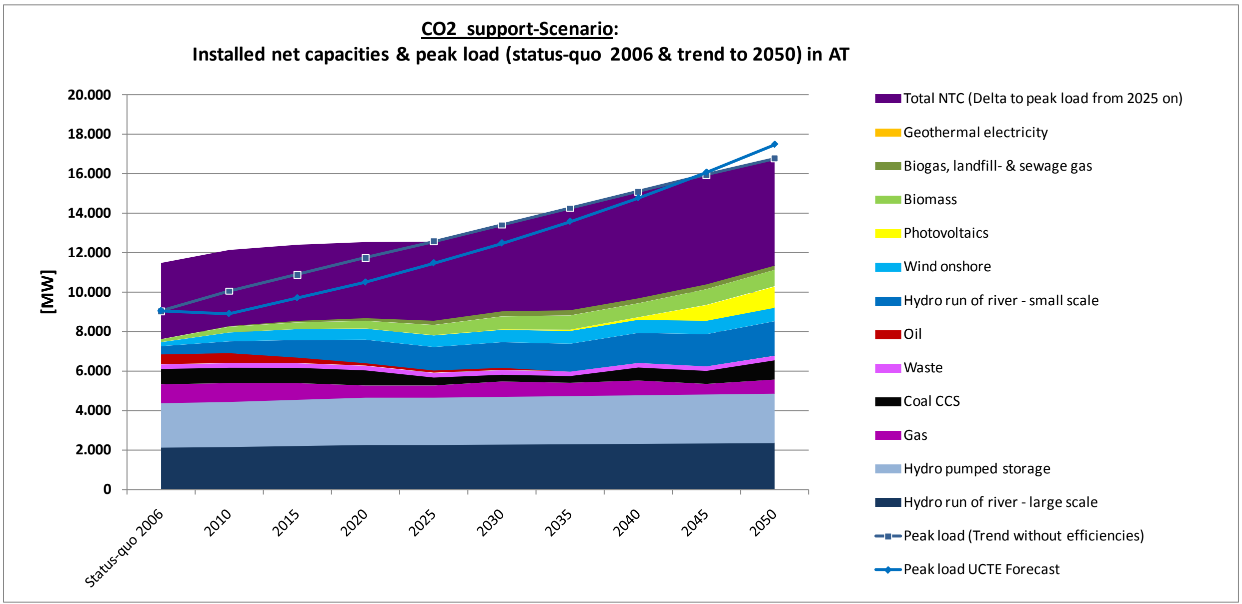

Figure 6: **Installed net capacities[3] (generation and NTC) as well as peak load forecasts to 2050 in Austria in the <u>CO2_support-Scenario</u>. Source: [3], [4], [5], [6] & own calculations.**

Finally in the “CO2_support”-Scenario the demand increases to 80 TWh until 2050 and primary energy and CO2 prices are increasing even more compared to the effres_support-Scenario (coal: 18 €/MWh, gas: 51 €/MWh, CO2: 59 €/tCO2, wholesale electricity: 109 €/MWh). Subsidies for new renewable power plants amount to between € 50 and € 80 million yearly. Carbon capture and storage technologies are used together with the coal power plants. So on the one hand additional gas and coal capacities are installed but on the other hand also small-scale PV and hydro as well as biomass power plants increase continually from 2040 on.

[3] Net capacities of generation units = rated capacities * (full load hours / 8760).

Furthermore, as listed in Table 1, the weighted average of total generation capacity costs per technology type in Austria is calculated. Weighted average means that the capacities' costs are weighted by their technologies' share in the Austrian power plants' park.

Table 1: Weighted average of generation cost data per technology. Source: [4], [19], [21] - [31] & own calculations and assumptions.

Average total generation capacity cost for Austria		Assumptions:
	[€/MW] real 2006	WACC = 6%
Hydro run of river - large scale	271.278	30 €/t-CO_2
Hydro pumped storage	97.346	
Gas	136.377	
Coal & lignite	228.607	
Waste	527.110	
Oil	163.632	
Hydro run of river - small scale	280.908	
Wind onshore	128.483	
Photovoltaics	618.842	
Biomass	368.214	
Biogas, landfill- & sewage gas	524.109	
Geothermal electricity	435.246	

These costs are derived by calculating the electricity generation costs (in €/MWh) for each technology multiplied by the full load hours of each technology derived from [4]. The assumptions made and the cost data taken from several literature sources for the several generation cost components of renewable and fossil fuel technologies are listed in Table 2 and Table 3.

Table 2: Assumptions and cost data for the generation cost per generation technology - renewables.

Generation capacity cost data & assumptions				
Technology	**Cost component**	**Value**	**Unit**	***Source***
Hydro run of river	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	40	years	*assumption*
	Yearly full load hours	>= 10MW: 4506 < 10MW: 5081	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*
Wind onshore	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	25	years	*Green-X [19]*
	Yearly full load hours	1800-2200	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*
Biomass	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	25	years	*Green-X [19]*
	Yearly full load hours	7000	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*
Geothermal electricity	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	22	years	*Green-X [19]*
	Yearly full load hours	7000	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*
Hydro pumped storage	Overnight investment costs	1500	€/kW	*average of [24] - [26]*
	Economic Lifetime	50	years	*Cole et al. [22]*
	Yearly full load hours	2912	hours	*E-Control [4]*
	Electric efficiency	0,765	1	*Schoenungen [24]*
	O&M costs	2,18	€/kW*yr	*Schoenungen [24]*
Photovoltaics	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	25	years	*Green-X [19]*
	Yearly full load hours	900	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*
Biogas, landfill- & sewage gas	Overnight investment costs	internal data	€/kW	*Green-X [19]*
	Economic Lifetime	25	years	*Green-X [19]*
	Yearly full load hours	7000	hours	*E-Control [4]*
	Electric efficiency		1	
	O&M costs	internal data	€/kW*yr	*Green-X [19]*

Table 3: Assumptions and cost data for the generation cost per generation technology – fossil fuels.

Generation capacity cost data & assumptions				
Technology	**Cost component**	**Value**	**Unit**	***Source***
Gas	Overnight investment costs	>= 200MW: 674 < 200MW: 700	€/kW	*OECD [23]*
	Economic Lifetime	20	years	*Assumption*
	Yearly full load hours	3147	hours	*E-Control [4]*
	Electric efficiency	0,6	1	*Wissel et al. [30]*
	Fuel costs	27,06	€/MWh	*BAFA [27]*
	Specific CO2 emissions	0,198	t-CO2/MWh	*Auer et al [28]*
	O&M costs	30,09	€/kW*yr	*average of [23] & [29]*
	Heat price	27,06	€/MWh	*BAFA [27]*
Waste	Overnight investment costs	>= 10MW: 6130 < 10MW: 3173	€/kW	*OECD [23]*
	Economic Lifetime	20	years	*Assumption*
	Yearly full load hours	6089	hours	*E-Control [4]*
	Electric efficiency	0,6	1	*Assumption*
	Fuel costs	21,78	€/MWh	*Heat suppliers in AT & assumption*
	Specific CO2 emissions	0,297	t-CO2/MWh	*Assumption*
	O&M costs	45,14	€/kW*yr	*Assumption*
	Heat price	21,78	€/MWh	*Heat suppliers in AT & assumption*
Coal & lignite	Overnight investment costs	>= 700MW: 908 >= 300MW: 438	€/kW	*OECD [23]*
	Economic Lifetime	20	years	*Assumption*
	Yearly full load hours	4672	hours	*E-Control [4]*
	Electric efficiency	0,46	1	*Wissel et al. [30]*
	Fuel costs	13,87	€/MWh	*BAFA [27]*
	Specific CO2 emissions	0,342	t-CO2/MWh	*Auer et al [28]*
	O&M costs	66,31	€/kW*yr	*average of [23] & [29]*
	Heat price	13,87	€/MWh	*BAFA [27]*
Oil	Overnight investment costs	>= 200MW: 636 < 200MW: 800	€/kW	*Palacios et al. [31] & assumption*
	Economic Lifetime	20	years	*Assumption*
	Yearly full load hours	3034	hours	*E-Control [4]*
	Electric efficiency	0,6	1	*Assumption*
	Fuel costs	41,84	€/MWh	*BAFA [27]*
	Specific CO2 emissions	0,288	t-CO2/MWh	*Auer et al [28]*
	O&M costs	30,09	€/kW*yr	*Assumption (Gas)*
	Heat price	41,84	€/MWh	*BAFA [27]*

As shown in Table 4 the valuation of the import capacity cost is done with the UCTE mix, i.e. the respective capacities' costs of the technologies mainly occurring in the UCTE generation mix are calculated in the same way as the national generation capacities' costs.

Table 4: Costs of the imported capacity according to the UCTE Mix. Source: [18], [4], [19], [21] - [31] & own calculations and assumptions.

Costs of UCTE Mix capacity (Imported)	Share on total UCTE mix	Technology costs [€/MW]	Weighted costs per UCTE Mix [€/MW]
Hydro	11,74%	216.511	25.418
Other renewables	4,29%	414.979	17.803
Fossile fuels	52,78%	263.931	139.303
Nuclear	30,82%	223.380	68.846
Other technologies	0,37%	279.700	1.035
Summe	**100,00%**	**1.398.501**	**252.405**

In the next section 2.2 the used cost data for the transmission and distribution grid is explained.

2.2 Future grid investments

As a starting point for the grid cost development, the available historic data range (1970-2003) from [11] for investments into the transmission (T) and distribution (D) grid is used. The investments between 2003 and 2006 are estimated by taking the average yearly growth rate from the last 10 years of available data (1993-2003). Finally for the estimation of the future data from 2006 to 2050 an average yearly refurbishment investment of € 26 million is assumed.[4] Figure 7 shows the resulting cumulated T&D grid investments until 2050.

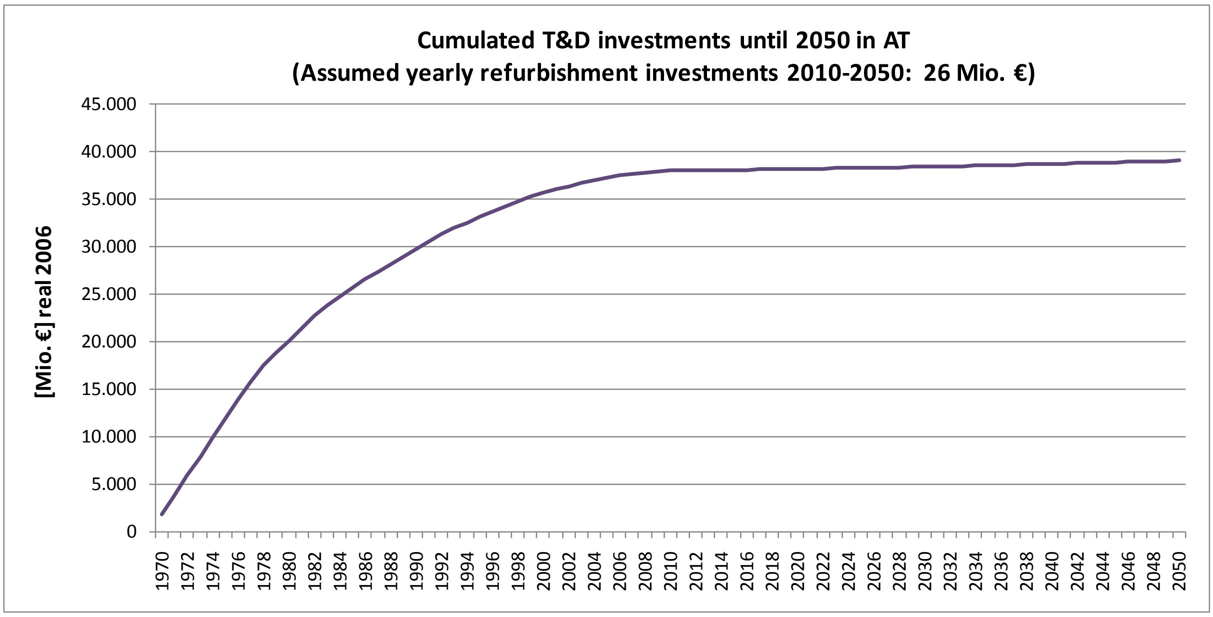

Figure 7: Cumulated transmission (T) and distribution (D) grid investments until 2050 in Austria. The average yearly refurbishment investments between 2010-2050 are assumed to be 26 Mio. €. Sources: [11], [15] & own calculations.

[4] This figure is an estimation discussed with experts from the Austrian Power Grid AG.

In the following tables the used grid investment data for grid investments is stated, which become necessary because of the changed structure of the installed thermal and/or renewable generation capacities in the three generation scenarios (additionally to the above assumed 'normal' refurbishment investments).

Table 5 shows the investment costs (distribution grid investment factors) of three demonstration-regions (calculated average) for 4 different distribution grid enhancement alternatives in € per kW. The grid enhancement in the distribution grid becomes necessary, if new renewable distributed power plants (with especially fluctuating electricity generation) are to be connected to the grid.

These distribution grid costs are based on the analysis of four different real case study regions in Austria within the project DG DemoNetz [1]. Within the framework of this project, solutions for challenges of the distribution grid (mainly caused by an increasing amount of distributed fluctuating (renewable) generation connected to critical grid points) were developed and their costs quantified. One major goal is to try to make the grid more 'active' or 'smarter' so that the fluctuating distributed amounts of electricity generation can be handled more efficiently and effectively, e.g. by implementing distributed or coordinated voltage control (DVC or CVC, respectively). The considerations and results of that project can be taken as a possible solution towards a 'smart grid'. Therefore, and because no other 'smart grid' cost data are already available, these cost data were taken for the calculation of the additional distribution grid costs caused by additional renewable capacities installed. Anyhow, it has to be mentioned, that by using these data, the results always have to be taken cautiously since the data evolved from particular Austrian regions. Generally speaking real electricity grids can rarely be compared to each other due to the specific properties of every grid.

However, the most expensive alternative among those 4 alternatives is the upper boundary cost of laying new grid lines and cables (the low alternative is an assumed 50% of the highest costs). The two other alternatives are distribution and coordinated voltage control, where the latter emerges to be the cheapest alternative compared to the connectable capacities.

Table 6 shows the yearly new and additional refurbishment investments in the Austrian transmission grid until 2020 which are planned by the Austrian Power Grid AG, the national transmission system operator (TSO). In total an amount of more than € 1 billion is projected in the next 10 years.

Table 5: Investment data for four different distribution grid enhancement alternatives in Austria. Source: [1] and own calculations.

Total average for 3 demo-regions in Austria	€/kW
Distributed Voltage Control (DVC)	140
Coordinated Voltage Control (CVC)	78
New Lines & Cables: upper boundary (high)	321
New Lines and Cables: low boundary (50% of the high value)	161

Table 6: Planned investments for the enhancement of the Austrian transmission grid until 2050. Soruce: [15].

Yearly new & refurbishment investments in the Austrian transmission grid											
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
[Mio. €] real 2006	108	108	108	108	108	108	108	108	108	108	1080

Table 7: <u>Transmission grid investment factor</u>: Total planned transmission grid investments per total estimated generation capacity increases until 2020 affecting the Austrian transmission grid. Source: [15] & own calculations.

Estimated capacity increase (large-scale)	Wind [MW]	Hydro pumped storage [MW]	Gas [MW]	Investments per MW capacity increase until 2020 [€/MW]
2010	1.000	1.200		
2011				
2012				
2013				
2014				
2015	1.700			
2016				
2017				
2018				
2019				
2020		5.500	4.700	
Zubau kumuliert	**700**	**4.300**	**4.700**	**111.340**

By taking into account the until then planned new generation capacities of 9000 MW thermal and 700 MW wind capacities which will be connected to the transmission grid (compare Table 7), a transmission grid investment factor of 111,300 € /MW capacity can be derived.

This transmission and distribution grid investment factors are then taken to calculate the grid investment costs caused by the installed (new andexisting) generation units, connected to the transmission (named 'Additional T costs') or distribution grid (named 'Additional D costs'), as will be explained in the next section. In addition the transmission investment factor is also taken to calculate the 'Inter-TSO costs'[5]. Further assumptions regarding the weighted average cost of capital, the lifetime of the grid and the O&M costs taken for these calculations (annuities of grid investments) are listed in Table 8.

Table 8: Assumptions for the calculation of grid cost annuities.

Assumptions for the calculation of grid cost annuities	
WACC	6%
O&M costs	10% of yearly investments
Lifetime	40 years

[5] Inter-TSO costs are the costs of building additional NTC capacity at the cross-border transmission lines.

2.3 The cost indicator

The goal within that paper is to observe the total system costs of a certain scenario, where the grid costs are dependent on the underlying generation mix, connected to the transmission or the distribution grid (given the assumptions and data explained above). In order to make both the generation and imported capacity costs as well as the grid costs comparable, a common cost indicator is developed: '€ per MW total installed capacity'.

That is, in a next step the annuities of the total costs of the generation and imported capacities as well as of the transmission and distribution grid costs (national and NTC) are calculated and then referred to that cost indicator. That means all generation costs (conventional and RES-E, the imported generation capacity costs (UCTE-Mix)) as well as the T&D grid costs (national and NTC) are divided by the cumulated amount of capacities installed in each year observed from 2006 to 2050. Schematically, the procedure is illustrated in Figure 8.

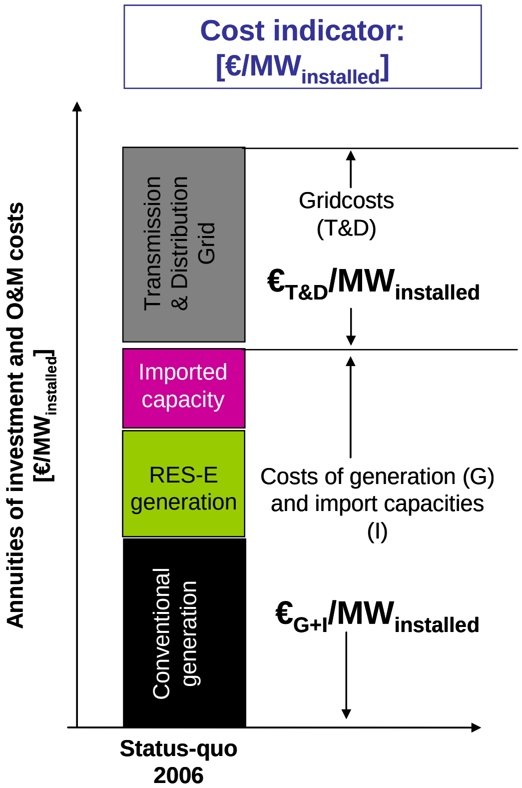

Figure 8: Schematic depiction of the cost indicator concept (annuities of investment and O&M costs) of generation and import capacity (UCTE-Mix) and D&T costs: All transferred to the cost indicator [€/MW$_{installed}$]. Own depiction.

By this procedure finally the future total system costs of the electricity supply system dependent on an underlying generation structure is derived. In the next chapter chosen results are demonstrated.

3 Results

In the following the results of the annuities of the total system costs in three scenarios are demonstrated: The REF (reference), the effres_support (efficiency and renewable with support) and the CO2_support (support for CO2 reduction) scenarios. So Figure 9, Figure 11 and Figure 13 show the costs of the additional capacities installed and the grid costs (T&D) in each year. The values below the x-axes show the costs saved (i.e. benefits) through decommissioned capacities. Additionally, for each scenario the resulting grid costs (T&D) are shown separately in order to be able to compare the resulting costs of the 4 possible distribution investment alternatives.

Firstly, Figure 9 shows the yearly total investments and O&M costs of the REF-Scenario. Total additional yearly costs of capacities and grids (annuities) start at 34,823 €/MW$_{installed}$ in 2010 and increases to nearly 51,000 €/MW$_{installed}$ until 2050. This is mainly due to the more than doubling of import capacities, which rise from 1,800 MW (18,572 €/MW$_{installed}$) in 2010 to 4,800 MW (over 36,000 €/MW$_{installed}$) in 2050. So the import dependency rises.

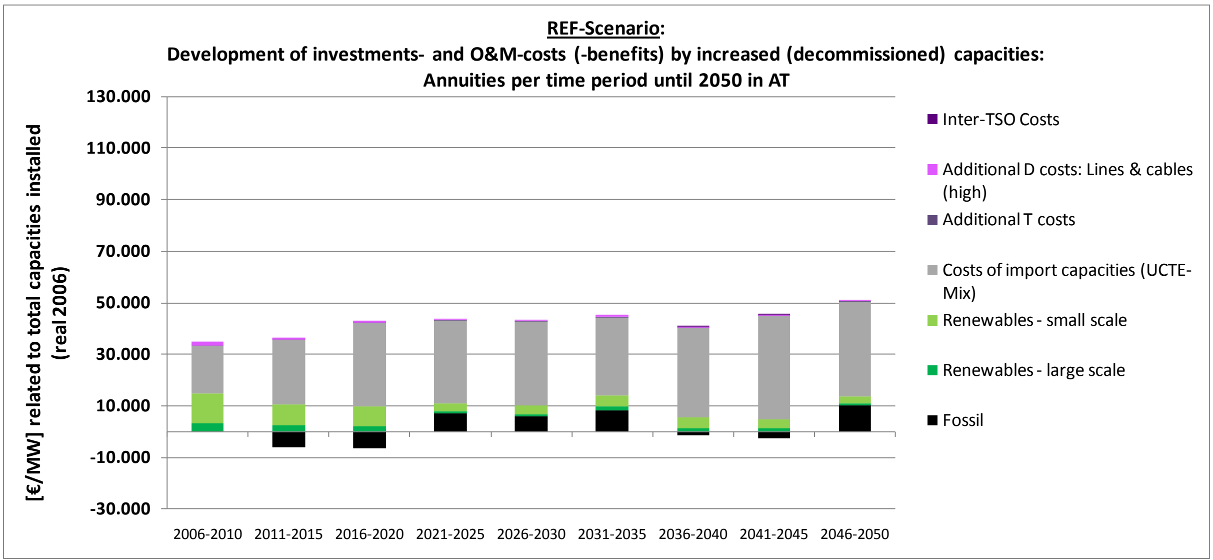

Figure 9: Yearly investment and O&M costs (benefits) of capacities and grid caused by increased (decommissioned) capacities until 2050 in Austria in the REF-Scenario.

The development of the yearly grid costs in the REF-Scenario is shown in Figure 10. The 'Inter-TSO costs' are dependent on the imported amount of capacity, whereas the 'Additional T costs' result according to the generation capacity connected to the transmission grid. Consequently, the 'Additional D costs' are dependent on the renewable generation capacity installed and integrated into the distribution grid. As regards the necessary grid reinforcements the reference scenario emerges to be a *hybrid grid scenario,* i.e. a mixture of necessary transmission (T) grid enhancements due to the additional import capacities affecting the NTC values and of the necessary distribution (D) grid enhancement due to additional amounts of renewable plants installed.

The graph has to be interpreted in the following way: The values of the single curves are added to one another, starting with ‚Inter-TSO costs', then added to ‚Additional T costs'. The remaining 4 distribution investment alternatives' curves show the total costs resulting, depending on which of the alternatives is deployed. I.e. the cheapest possibility is the 'CVC' (coordinated voltage control) method. So the cheapest total grid costs between 2006 and 2010 amount to 454 €/MW$_{installed}$. The peak of yearly costs would lie at 555 €/MW$_{installed}$ due to the high amount of renewable capacities installed in that period between 2031 and 2035. The most expensive alternative is 'laying lines and cables'. But it has to be mentioned, that the 'passive', and therefore 'business-as-usual' method, namely just reinforcing the grid by laying lines and cables like it was the practise in the past and also still today is taken as a *reference line* for comparison with the other two following scenarios. This is because the overall question within this paper stated in the introduction in Chapter 1 is to find out whether alternative grid scenarios (like a more 'active' or 'smart' grid) mean higher costs to society than a business-as-usual grid enhancement.

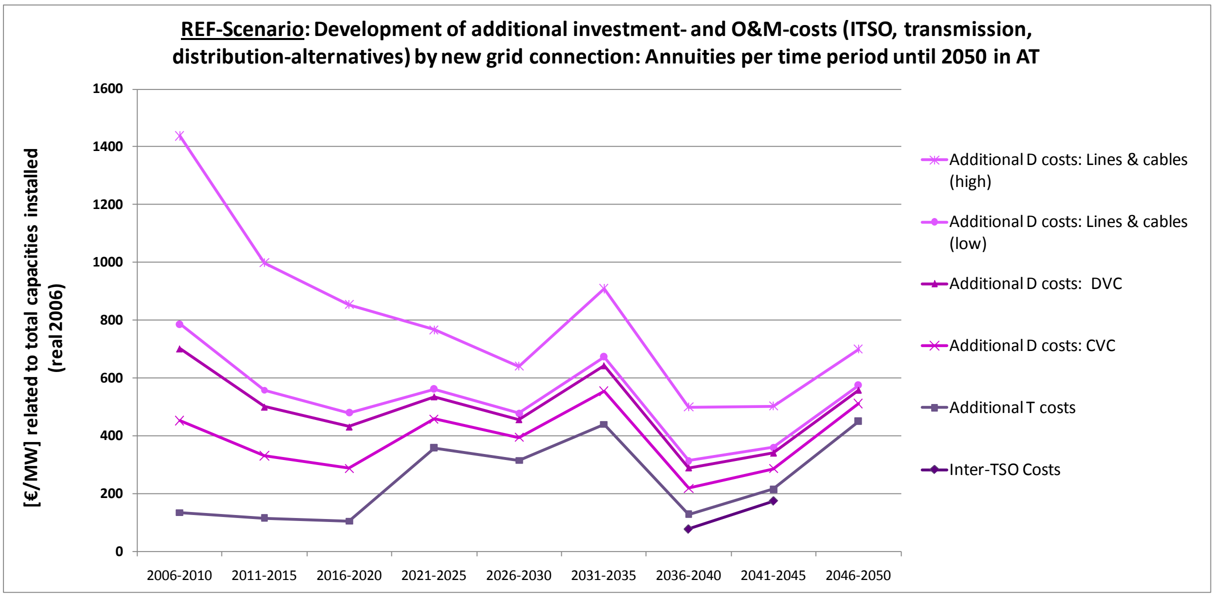

Figure 10: Yearly weighted additional investments and O&M-costs for additional import capacities (inter-TSO costs), transmission costs and 4 cost alternatives in the distribution grid caused by new grid connection until 2050 in Austria in the REF-Scenario.

Figure 11 and Figure 12 show the results for the effres_suppport-Scenario. Here, the level of the total yearly additional costs lies quite below the level of the REF-Scenario (dashed line) although far higher rates of renewable capacities are installed until 2045. The low cost is mainly due to the low electricity demand rates because of successful demand-side efficiency measures.[6] Anyhow, between 2046 and 2050 much higher costs result because of the high amount of renewable capacity. Total annual system costs between 2046 and 2050 amount to more than 81,000 €/$MW_{installed}$.

[6] Implementing demand-side measures also cause costs on the grid but are not taken into account within that paper.

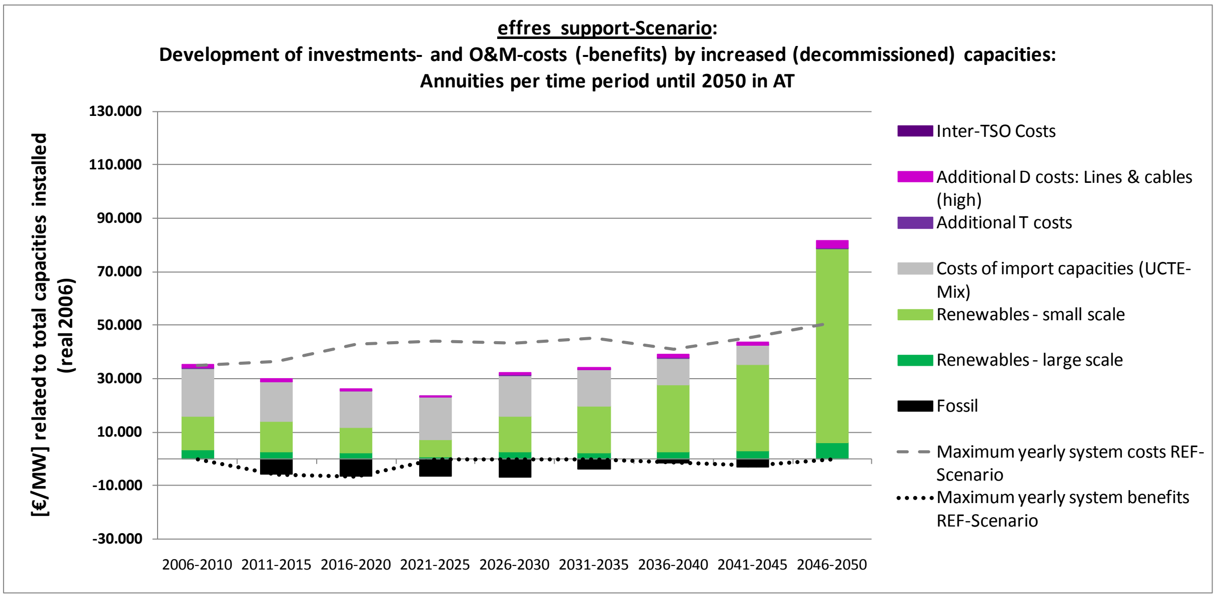

Figure 11: Yearly investment and O&M costs (benefits) of capacities and grid caused by increased (decommissioned) capacities until 2050 in Austria in the effres_support-Scenario.

Additionally it can be seen that the benefits resulting from decommissioned capacities (especially fossil capacities) is higher than in the REF-Scenario (punctuated curve) because most coal and gas plants are decommissioned.

The shaded area in Figure 12 also allows a comparison of the grid costs to the respective maximum level of the REF grid costs. Here as well, because no additional costs through an increase of the NTC values occur (no new NTC is necessary, because demand increases until 2050 in the effres_support-Scenario), overall grid costs are lower even than the maximum REF-grid costs level until 2045. After 2045, the distribution grid costs increase due to the installed renewable capacity on the distribution grid. I.e. in the effre_support-Scenario - by taking one of the 'active' grid alternatives, namely 'CVC' or 'DVC' - grid costs can be kept on a low level compared to the REF-Scenario (at the maximum reaching about 700 €/MW$_{\text{installed}}$ in the period between 2046 and 2050) and even enable the integration of high amounts of renewable capacities into the grid. This application therefore, can be called a 'smart grid'-Scenario due to the major role and impact of the active distribution grid on overall grid costs.

But, as can be seen from Figure 11, the grid costs' share on total yearly additional system costs (even the most expensive alternative 'Lines & cables high') is small. That means the influencing factor for society's costs here is not the grid costs but the generation capacities' cost.

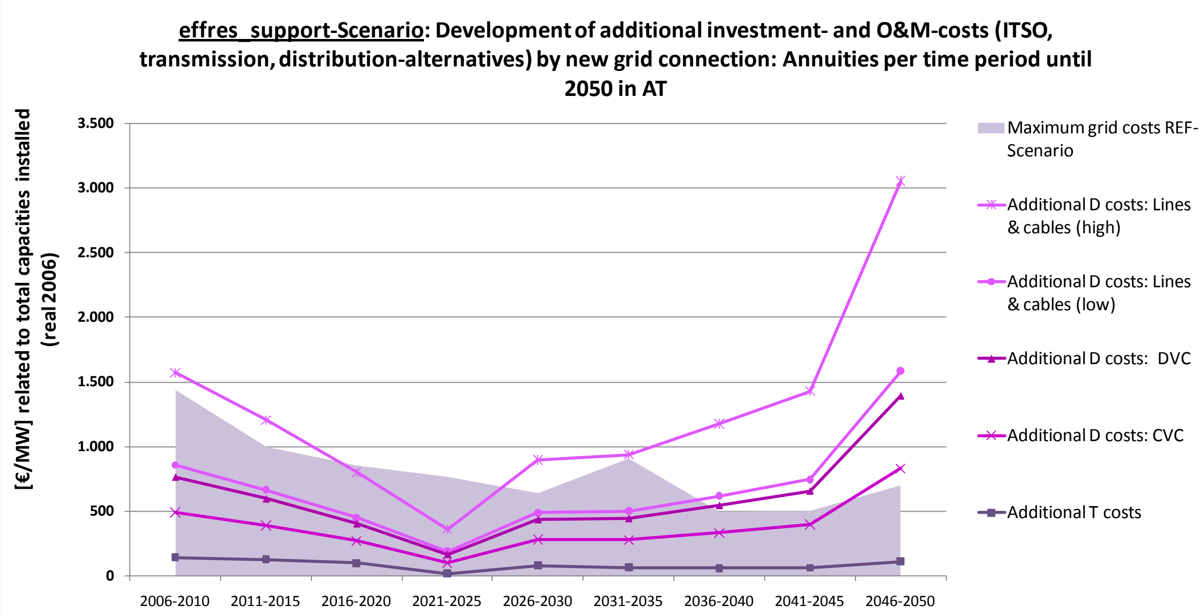

Figure 12: **Yearly weighted additional investments and O&M-costs for additional import capacities (inter-TSO costs), transmission costs and 4 cost alternatives in the distribution grid caused by new grid connection until 2050 in Austria in the <u>effres_support-Scenario</u> and maximum <u>REF</u>-costs.**

Finally, Figure 13 and Figure 14 demonstrate the results of the CO2_support-Scenario. In that case, no efficiency measures are incorporated and so, demand does not decrease. Consequently, in order to cover peak load (as demonstrated in Figure 6 and explained in chapter 2.1) additional import capacity is necessary, which results in high costs for imported capacities.

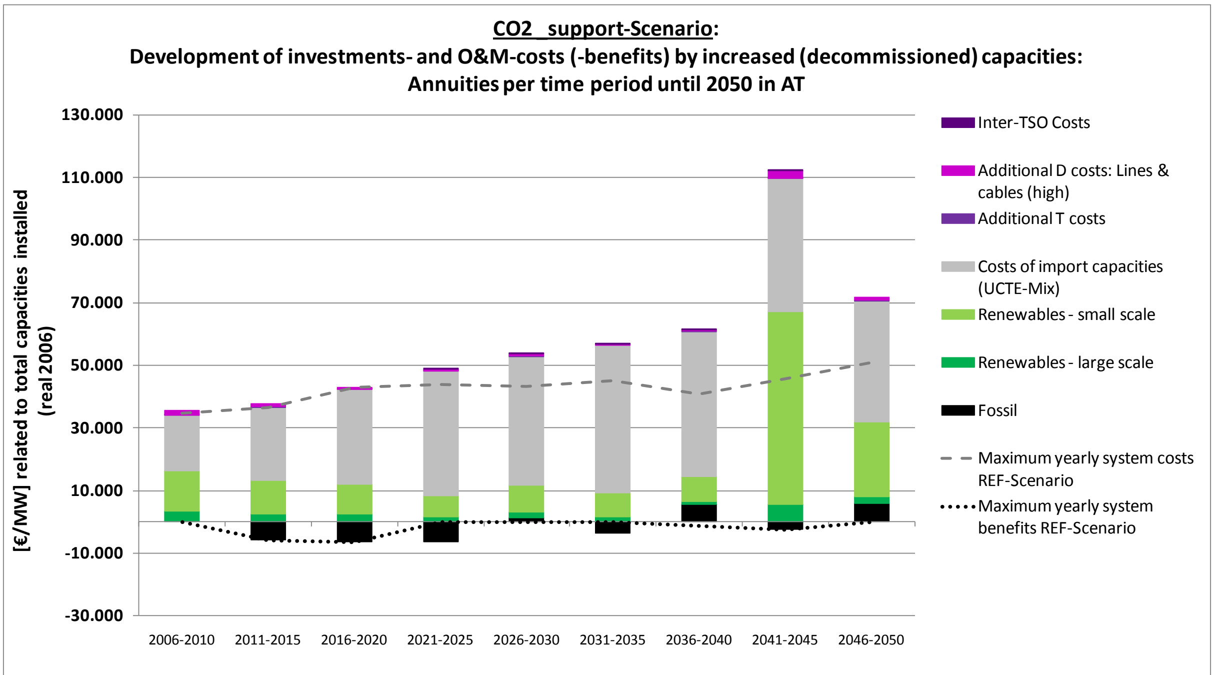

Figure 13: **Yearly investment and O&M costs (benefits) of capacities and grid caused by increased (decommissioned) capacities until 2050 in Austria in the <u>CO2_support-Scenario</u>.**

Additionally, besides the additional increase in fossil power plants (especially coal with carbon capture and storage technology), also the share of renewable energy technologies in the power plant park increases and results in higher costs than in the REF-Scenario too. Though some additional benefits through decommissioned old coal and oil power plants can be generated this cannot offset the higher costs by renewable and import capacity.

The comparison of the grid costs in the CO2_support-Scenario shows a similar picture than for the effres_support-Scenario.

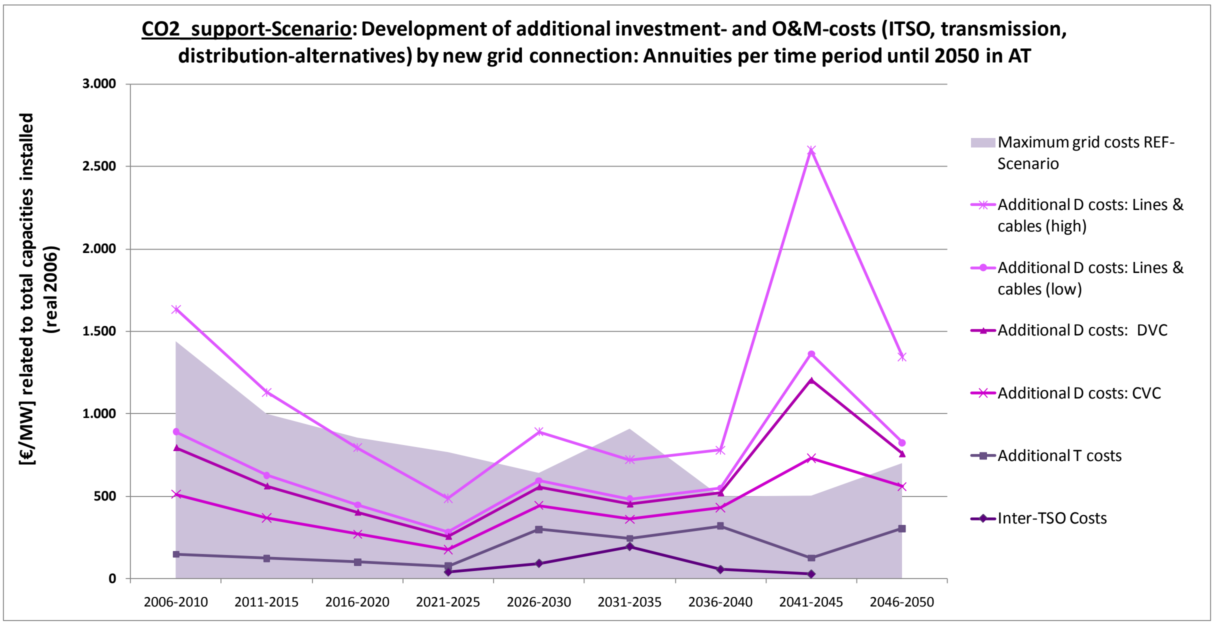

Figure 14: **Yearly weighted additional investments and O&M-costs for additional import capacities (inter-TSO costs), transmission costs and 4 cost alternatives in the distribution grid caused by new grid connection until 2050 in Austria in the CO2_support-Scenario and maximum REF-costs.**

Additional distribution grid costs emerge to be highest in periods where a high additional amount of renewable capacities are installed, i.e. in the period between 2041 and 2045 and but jump to about 700 €/MW$_{installed}$ by taking the 'CVC' alternative. 'Inter-TSO costs' contribute to the grid cost level due to the level of imported capacity (NTC levels increase in that scenario as explained above). Again, by deciding for the alternative active grid approach, namely by implementing coordinated or distributed voltage control on a broad level, total grid costs can be held low despite increased renewable penetration and import (and so transmission grid) dependency.

4 Conclusions and outlook

The results clearly show that the level of the resulting additional grid costs compared to the resulting annual costs for generation or import capacities is low and do not have exceptional weight if considering the whole electricity supply system. The highest cost impact in the overall electricity supply system can be allocated on the one hand to the renewable capacities, which still are much more costly than conventional fossil technologies in 40 years (including learning rates but also necessary subsidies). On the other hand, the imported capacity also affects total system costs in the REF- and CO2-Scenario. This shows that high import capacities are necessary, if no additional efficiency and/or peak load shifting measures can be introduced successfully.

Comparing the grid costs among themselves, the highest impact can be seen as regards the distribution grid costs, since firstly, the cost per MW are higher than the transmission costs (except the CVC alternative) and secondly, they are dependent on the additional installed renewable capacity amounts. But by applying an *active* method like especially coordinated voltage control, the overall level of grid costs can be kept low in the effres_support- as well as in the CO2_support-Scenario compared to a passive business-as-usual grid enhancement approach: Just laying lines and cables. So answering the question, whether a new *active* or *smart* grid system implies extra cost to society, it can be answered with 'yes' as regards the additional costs generated by a 'greener' shape of the power plants park. Regarding the impacts on the grid costs, the results show that there is a possibility to reach lower costs with alternative grid enhancement methods. But its adaptability and functionality on an Austrian-wide scale still has to be analysed and tested. However, given the method can be applied all over Austria and the costs do not vary substantially among other than the tested grid areas coordinated voltage control not only would enable the broad penetration of distributed, fluctuating electricity generation, but also form the cheapest possibility.

Summarizing, the scope of that analysis neither was to show the cheapest possible electricity supply system in 2050 nor a cost/benefit analysis of the several scenarios. And it is clear, that it is a political decision which system has to be aimed at in future. If the wish is to decrease carbon emissions thoroughly and make the generation mix as green as possible, higher electricity system costs have to be accepted.

However, to be able to draw a more detailed picture about the interrelations of the different cost components within the total electricity supply system, a fine-tuned sensitivity analysis of the used data as well as the assumptions has to be undertaken in future research.

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