



CEEPR

Center for Energy and Environmental Policy Research

**Effects of the Uncertainty about Global Economic
Recovery on Energy Transition and CO₂ Price**

by

**Olivier Durand-Lasserve, Axel Pierru and
Yves Smeers**

11-003

March 2011

**A Joint Center of the Department of Economics,
MIT Energy Initiative, and Sloan School of Management**

Effects of the Uncertainty about Global Economic Recovery on Energy Transition and CO₂ Price

Olivier Durand-Lasserve^{a,b,1,2}, Axel Pierru^b and Yves Smeers^a

^a*Catholic University of Louvain (UCL), CORE, Voie du Roman Pays 34, B-1348 Louvain-la-Neuve, Belgium.*

^b*IFP Energies nouvelles, Economics Department, 232 Avenue Napoléon Bonaparte, 92852 Rueil-Malmaison, France.*

Abstract

This paper examines the impact that uncertainty over economic growth may have on global energy transition and CO₂ prices. We use a general-equilibrium model derived from MERGE, and define several stochastic scenarios for economic growth. Each scenario is characterized by the likelihood of a rapid global economic recovery. More precisely, during each decade, global economy may - with a given probability - shift from the EIA's (2010) low-economic-growth path to the EIA's (2010) high-economic-growth path. The climate policy considered corresponds in the medium term to the commitments announced after the Copenhagen conference, and in the long term to a reduction of 25% in global energy-related CO₂ emissions (with respect to 2005). For the prices of CO₂ and electricity, as well as for the implementation of CCS, the branches of the resulting stochastic trajectories appear to be heavily influenced by agents' initial expectations of future economic growth and by the economic growth actually realized. Thus, in 2040, the global price of CO₂ may range from \$21 (when an initially-anticipated economic recovery never occurs) to \$128 (in case of non-anticipated rapid economic recovery). In addition, we show that within each region, the model internalizes the constraints limiting the expansion of each power-generation technology through the price paid by the power utility for the acquisition of new production capacity. As a result, in China, the curves of endogenous investment costs for onshore and offshore wind are all bubble-shaped centered on 2025, a date which corresponds to the establishment of a global CO₂ cap-and-trade market in the model.

1. Introduction

OECD countries are already committed to reductions in greenhouse-gases emissions by 2020. In the longer term, these countries must in any case assume a leadership role in the field of emissions reduction, in order for less-developed economies to accept reductions in their own emissions. This implies significant restructuring of their energy systems, through the deployment of low-carbon emissions technologies. However, this restructuring is contingent on considerable short and medium-term investment in infrastructures whose lifetime is in general very long. In a climate of uncertainty, such investments must offer sufficient expected returns to attract the necessary capital.

There have been relatively few studies using dynamic general-equilibrium models under environmental constraints to determine equilibria that take into account the influence of uncertainty

¹ Corresponding author. Tel.: +32 10 474358, fax: +32 10 474301.

Email addresses: olivier.durand@uclouvain.be (Olivier Durand-Lasserve), axel.pierru@ifpen.fr (Axel Pierru), yves.smeers@uclouvain.ac.be (Yves Smeers).

² This author has been financially supported by GDF-Suez. The results in this article do not necessarily reflect the opinions of UCL and IFP Energies nouvelles. The authors gratefully thank Thomas F. Rutherford and Geoffrey J. Blanford for granting full access to the code of the MERGE model.

on agents' behavior. Manne and Richels (1995) and Manne and Olsen (1996) study the impact of the uncertainty surrounding the sensitivity of climate damages to greenhouse-gases concentrations. Bosetti et al. (2009) and Durand-Lasserve et al. (2010) study the impact of uncertainty relative to regional emissions-reduction targets. Bosetti and Tavoni (2009) consider the uncertainty over the success of R&D activities concerning a backstop technology. De Cian and Tavoni (2010) evaluate the effect of uncertainty in future carbon prices and technology costs. However, none³ of these contributions investigates the impact that uncertainty over global economic growth may have on technological choices and resulting CO₂ price.

The recent economic and financial crises, which have particularly affected certain OECD regions, have ushered in a period of great uncertainty. Above and beyond the question of short-term business cycle, this uncertainty affects the capacity of these economies to grow at a sufficient rate in the longer term. Several institutional analyses (OECD (2010), IMF (2010)) emphasize in particular the long-term impact of the rise in unemployment linked to the crisis⁴, as well as concern over the sustainability of the national-debt burden of some industrialized countries⁵. Consequently, the recent crisis may be followed by one or more decades of very low growth, similar to the "lost decades" experienced by the Japanese economy since the beginning of the 1990s. This uncertainty over economic growth in industrialized countries, and more generally over global economic growth, may represent a major obstacle to the executions of the investments necessary for change in the energy mix. Thus, in developing countries with high economic growth (where elasticity of energy demand to GDP is relatively high) this uncertainty may slow the growth of the energy supply. In industrialized countries with moderate economic growth (and in the longer term on a global scale), this uncertainty may slow the adaptation of the energy mix to targeted reductions in CO₂ emissions.

In his address to the 2010 World Energy Congress, Fatih Birol, Chief Economist of the International Energy Agency (IEA), declared that the energy industry was confronted by a "level of uncertainty that is unprecedented", placing the uncertainty linked to "the shape and pace of economic recovery following the worst global recession since World War Two" at the highest rank of the "crucial factors" that will have an impact on investment decisions in the energy sector⁶. This concern is shared by the Energy Information Administration (DOE/EIA), for which "expectations for the future rates of economic growth are a major source of uncertainty" (EIA (2010), p.20). To reflect this uncertainty the EIA (2010) presents three scenarios for global economic growth by 2035. A result put forward is the extreme sensitivity of energy demand to the economic-growth scenario.

³ Research works dealing with economic-growth uncertainty (e.g., Scott et al. (1999), Webster et al. (2008)) generally use methods relating to Monte-Carlo simulation.

⁴ "[...] there continues to be a risk that at least part of the rise in unemployment since the crisis began will prove long-lasting". (OECD (2010), p. 40).

⁵ "In particular, new tail-risks have arisen from the growing concerns about longer-term debt sustainability in some countries [...]" (OECD (2010), p.43).

"Greece accounts for less than 3 percent of the European Union's total GDP, but signs of structural problems in the economies of Spain, Portugal, Ireland, and to a lesser extent Italy may weigh heavily on the economic recovery of OECD Europe as a whole [...]" (IEO, 2010).

⁶ "Some economists say the recovery will take a long time. Some say we will see a second recession. And some say that we will soon see a strong rebound. This is important for decision-makers, especially for investment in the energy industry." in "An outlook of 'unprecedented uncertainty'", European Energy Review, 20/09/2010, <http://www.europeanenergyreview.eu/index.php?id=2353>.

This paper studies the impact that uncertainty over economic growth may have on the choice of the global energy mix and resulting CO₂ prices. To do so, we define stochastic scenarios for economic growth inspired by the EIA's (2010) scenarios. The uncertainty relates to the period during which the global economy may once again take a path of solid growth. The climate policy considered corresponds in the medium term to the commitments announced after the 2009 Copenhagen conference, and in the long term to a reduction of 25% in global energy-related CO₂ emissions (with respect to 2005). Using stochastic dynamic programming, we solve a general-equilibrium model similar to that described by Durand-Lasserve et al. (2010), derived from MERGE (Manne et al. (1995)). In this model, all agents are forward looking, in the sense that each representative household (firm) maximizes its expected sum of discounted utilities (expected present value) under rational expectations. In other words, on every date firms base their current decisions on consistent subsequent prices and outputs on every possible outcome. These decisions are influenced in particular by irreversibilities resulting from investments and technological choices. At economic equilibrium, for each variable (for instance CO₂, oil, gas and power prices) the model derives a stochastic scenario consistent with that assumed for economic growth.

The following section more precisely describes the stochastic economic-growth scenarios considered. The general-equilibrium model used is then described briefly, emphasizing the different forms of irreversibility taken into account. The CO₂ emissions targets considered for the various regions of the world are presented. Several comments on the calibration of the model form a particular subsection. We then present and interpret the results obtained, identifying the impact of the uncertainty under consideration on prices and on the global energy transition. Technological trajectories, CO₂ prices and electricity prices are studied in turn. Finally, we demonstrate that the existence of constraints limiting the expansion of each power-generation technology is equivalent to rendering endogenous the price paid by the power utility for the acquisition of additional production capacity. For wind technologies, the formation of this endogenous investment cost is analysed.

2. Stochastic scenario for global economic growth

We consider that the global economy may experience a period of slow growth, before returning to a high growth rate. The uncertainty centres on the number of decades of low growth (i.e. of "lost decades", to borrow the expression used by Hayashi and Prescott (2002) about the Japanese economy) through which the global economy must pass before experiencing an economic recovery. More precisely, during each decade beginning in 2015, 2025 and 2035, global economic growth may, with the probability p , escape from the path of low growth to shift to a path of higher growth (on which it will subsequently remain). In other words, the higher the value of p , the more likely a rapid economic recovery.

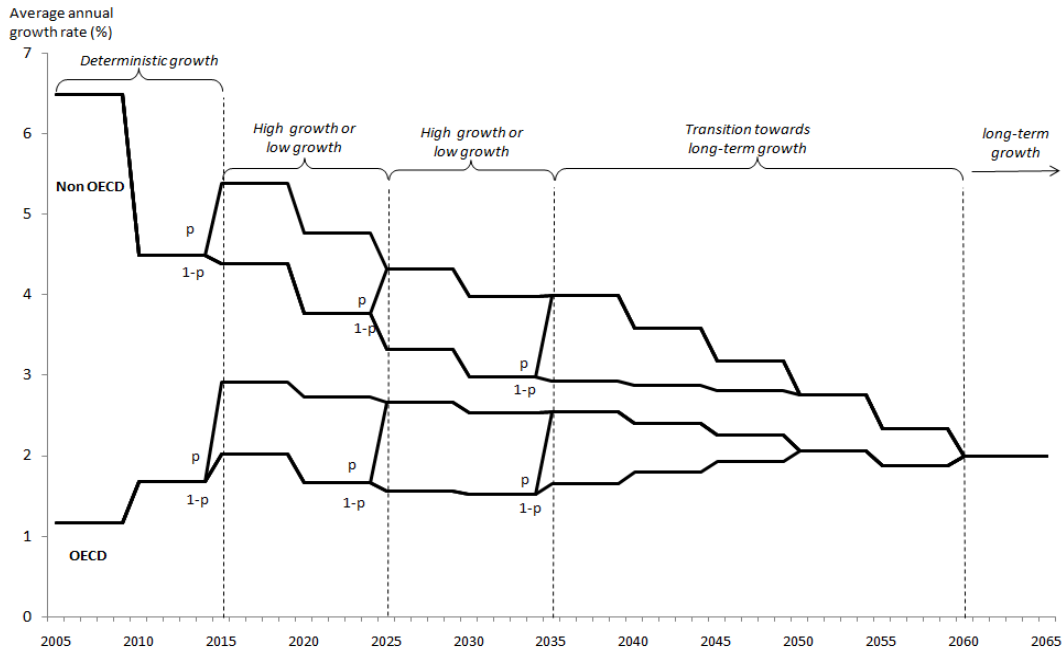


Figure 1: Possible GDP growth rates in OECD and non-OECD.

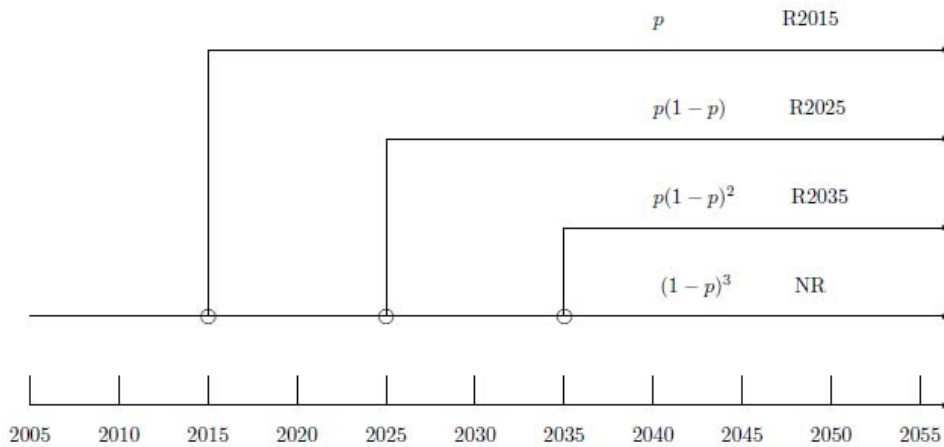


Figure 2: Structure of the stochastic scenario for each variable of the model.

These two possible growth paths correspond to the EIA's (2010) high and low economic-growth scenarios. Each path defines specific economic-growth rates for each of the regions in the model.

On a global scale, the high-growth path implies growth rates around 1% higher than those corresponding to the low-growth path, as shown by Figure 1. However, this differential varies according to the region considered. Up to 2015, the economic growth is deterministic and corresponds to the EIA's (2010) reference scenario. In all regions of the world, the two growth paths begin to converge from 2035. From 2060 on, all regional economies grow at the annual rate of 2%.

For each variable (price or quantity), the model will derive a stochastic scenario consistent with that considered for economic growth. This stochastic scenario may be represented by a tree with four branches, each branch defining one possible path the variable under consideration. In the remainder of the paper, these paths are named *R2015* (economic recovery in 2015, with probability p), *R2025* (economic recovery in 2025, with probability $p(1-p)$), *R2035* (economic recovery in 2035, with probability $p(1-p)^2$) and *NR* (no economic recovery, with probability $(1-p)^3$). A new branch appears on each possible date of economic recovery, as shown in Figure 2.

3. Presentation of the model

3.1 General overview

The general equilibrium model SMERGE used, derived from MERGE (Manne et al. (1995)), is essentially that described by Durand-Lasserve et al. (2010). The model's horizon extends from 2005 (base year) to 2100, with 5-year time periods. The world is divided into 3 OECD regions (European Union, North America, OECD Pacific) and 8 non-OECD regions (Africa, China, India, Latin America, Middle East, non-OECD Asia, Russia, Rest of the World). The economic-growth stochastic scenario is common knowledge and all agents in the model are equally informed and have perfect foresight. In each region, a representative household maximizes the expected sum of discounted logarithmic utilities of per-capita consumption over time and states.

The good consumed by households is a composite good that includes all intermediate and consumption goods and services, as well as all the final energy needs of the economy (firms and households). It serves as a numeraire, measured in terms of units of purchasing power for the year 2005. This composite good can be used for final consumption (by households), investment, and intermediate consumption (in industrial sectors). This composite good is produced in each region by a final industrial sector using various equipment vintages. At any given period, the production function corresponding to a new vintage of installed equipment is described by a two-level nested Constant Elasticity of Substitution (CES) function, using four inputs: labor, capital, electricity and non-electric energy. However, once the vintage is installed, the respective quantities of these inputs can no longer be adjusted. The resulting coexistence of different vintages in the final sector generates irreversibility, since this sector is somehow locked in the short run by previous technical choices. For instance, the choice of the energy intensity of new vintages until 2015 impacts the possible substitutions after this period between capital and energy and between electricity and non-electric energy.

Electricity and non-electric energy are supplied to the final sector by two distinct industrial sectors that use various Leontief technologies to transform fossil fuels and composite goods into energy. The technologies in the non-electric sector are: oil for direct use, gas for direct use, coal for direct use, bio-fuels, synthetic fuels, and non-electric backstop (see Durand-Lasserve et al. (2010) for a precise description). The power generation technologies are shown in Table 1.

Our model explicitly considers sunk investment costs for each power generation technology, which renders irreversible the cost of a capacity increase. On this point, our model differs from that used by Durand-Lasserve et al. (2010), who, for each technology at each period, consider a total cost equal to a levelized cost multiplied by the production during that period. In their model, the absence

of unrecoverable investment costs was compensated for by a constraint limiting the possible rate of decline in the use of the technology.

Moreover, in our model, investments are subject to time-to-build: 10 years (2 periods in the model) for nuclear technologies with CCS and non-electric backstop, 5 years (one period) for the other technologies. Considering time-to-build increases the uncertainty over energy demand and prices when investment decisions have to be made. Note that, for all technologies, installed capacity decays at an annual rate of 2%.

Table 1: Power generation technologies in the model (Sources: IEA (2008a), IEA⁷ (2010a,b)).

Technology	Investment cost ^c (\$ per kWe)		Efficiency (%)		Emission rate (TCO ₂ /MWh)		Load factor (%)	
	2010	2050	2010	2050	2010	2050	2010	2050
Hydropower	2410-3210	3010-3330	-	-	-	-	23-54	30-50
Remaining nuclear	-	-	-	-	-	-	85	-
New nuclear	2000-2500	3670-4000	-	-	-	-	85	85
Remaining oil	-	-	30-54	-	0.57-0.87	-	18-49	-
Remaining coal	-	-	26-39	-	0.86-1.39	-	43-75	-
Remaining coal with CCS ^a	880-1390	-	20-33	-	0.09-0.14	-	70	-
New coal	700-1750	2530-2070	42-44	47	0.76-0.89	0.71-0.78	48-80	43-88
New coal with CCS ^a	1510-3120	3140-3780	34-36	39	0.05-0.06	0.05	85	85
Remaining gas	-	-	36-54	-	0.37-0.62	-	20-54	-
New gas	600-700	820-900	55-59	63	0.34-0.40	0.33	41-64	40-64
New gas with CCS ^a	1080-1260	1430-1490	47-51	55	0.02	0.02	85	85
Biomass	2130-2480	2120-2220	-	-	-	-	25-71	65
Wind onshore	1390-1730	1410-1520	-	-	-	-	18-24	30-33
Wind offshore	2570-3180	1670-1740	-	-	-	-	35-39	39-40
Solar photovoltaic	3900-4650	1910-2020	-	-	-	-	11-17	12-33
Electric backstop ^b	6140-7220	3090-3410	-	-	-	-	40	40

^aA 10\$/T CO₂ transportation-and-storage cost is considered, in accordance with Rafaj and Kypreos (2007) and the (wide) range of estimates given by IEA (2010b). ^b Includes concentrating solar power and marine energy. ^c In addition to investment costs, variable and fixed non-fuel O&M costs are also considered (along with a variable feedstock cost for nuclear and biomass power plants).

The model includes constraints on the maximum expansion of each technology. These constraints, which take the form of a maximum growth rate in technology deployment from one period to the other, reflect real-world frictions when installing new capacity. For new technologies, they also cover the inertia inherent in the emergence of a new industrial sector, an inertia which may be explained by the fact that new competing technologies face infrastructural, institutional and cultural barriers (Köhler et al. (2006)). In other words, the development and spread of any technology is in essence a gradual process, which may for example be shown by an S-shaped curve

⁷ Main IEA (2010b) cost assumptions available at: <http://www.worldenergyoutlook.org/investments.asp> (accessed 5 January 2011).

(e.g. Könnöla and Carrillo-Hermosilla (2008)) whose take-off and acceleration phases would be mimicked by the constraints on expansion. These constraints therefore generate a path dependence - in the absence of learning curves in the model - linked to the organization of the sector, which makes adaptation of the energy system even more difficult during an economic recovery, especially if it was not properly anticipated.

In each region, a single electricity demand is considered for each period. So as to consider an energy mix compatible with an averaged demand, the maximum market shares of nuclear, wind and solar technologies are limited (33% of total power generation for each). Similarly, a minimum of 10% of the total installed capacity must consist of technologies based on fossil fuels, as a complement to intermittent technologies and because of the existence of peak demands. Furthermore, capacities in hydropower and biomass are subject to exogenous availability limitations.

The fossil fuels are supplied by a mining firm that extracts oil, coal and gas from regional reserves. All regions are linked together by the international trade in composite good, oil and gas. An indexation of the variables (Meeraus and Rutherford (2005)) corresponding to the structure of the stochastic scenario for economic growth replaces the explicit specification of non-anticipativity constraints. Additional aspects of the calibration and numerical resolution of the model are described by Durand-Lasserve et al. (2010).

3.2 CO₂ emissions policy in the model

Table 2 describes the gradual energy-related CO₂ emissions reductions targets⁸ assumed for the various regions of the world. In the long term, the objective is to reduce global emissions by 25% between 2005 and 2050, with all regional quotas allocated from 2050 (and up to 2100) corresponding to the same *per capita* volume of emissions. Based on the demographic projections used by the EIA (2010), this *per capita* volume of emissions is 2.21 tons of CO₂ per year.

To attain this objective, OECD regions, Russia, China, the Middle East and Rest of the world will have to decrease their CO₂ emissions between 2005 and 2050. Conversely, regions where the current *per capita* volume of CO₂ emissions is low may increase their emissions (+372% for Africa, +198% for India, +136% for non-OECD Asia and +48% for Latin America). These targets of emissions reductions for 2050 have been established within the framework of a global cap-and-trade market for CO₂ emissions (i.e. a global market with inter-regional trading of emissions permits) from 2025 onwards. From that date, during each period, a quota of emissions permits is attributed to every region. The series of quotas allocated to the various regions are set so as to converge linearly towards the same *per capita* volume of CO₂ emissions in 2050. Unused emissions permits can be banked, to be used during a subsequent period. By consuming fossil fuels, the sectors supplying electricity and non-electric energy produce CO₂ emissions. In each region, in any period, the quantity de CO₂ emitted by these two sectors must therefore be smaller than the regional quota, increased by the emission permits banked in previous periods, and by the purchase of emissions permits from other regions.

⁸ Our model – which does not contain any modelling of the impact of GHG emissions on climate change – implicitly considers regional CO₂ emissions permit markets.

In addition to this long-term objective, there are regional targets of emissions reductions for 2020. These targets (WRI (2010a,b)) follow the commitments announced after the 2009 Copenhagen conference.

OECD Regions have committed to reduce emissions by 2020: -20% for the European Union, -17% for North America and OECD Pacific (relative to 1990 levels of emissions). In the model, each of these regions implements (from 2010 to 2020) a regional cap-and-trade market (not linked to other regions) and progressively decreases the allocated quota of emissions permits (i.e., the cap) so as to converge linearly towards its 2020 emissions target. In each region, banking of permits is allowed from 2010 onwards, with the option to use the banked permits within the global emissions-permits market (from 2025 on).

Table 2: Regional emissions-reduction targets

	2005	2020					2050				
	Level (GT)	Emission limit	CO ₂ intensity of GDP	Base year	Level (GT)		Change 2005-2020		Per capita emissions (T)	Level (GT)	Change 2005-2050
North America	6.88	-15%	-	1990	5.71		-17%		2.21	1.42	-79%
European Union	4.10	-20%	-	1990	3.32		-19%			1.29	-69%
OECD Pacific	2.19	-15%		1990	1.82		-17%			0.41	-81%
China	5.46	-	-40%	2005	10.78^c	10.27^d	+97%^c	+88%^d		3.21	-41%
India	1.23	-	-20%	2005	2.63^c	2.51^d	+113%^c	+103%^d		3.68	+198%
Russia	1.57	-15%		1990	1.83		+17%			0.25	-84%
Middle East	1.32	-	-	2020 ^a	2.10		+60%			0.80	-39%
Non-OECD Asia	1.50	-	-	2020 ^a	2.01		+34%			3.53	+136%
Latin America	1.00	+25%	-	2005 ^b	1.25		+41%			1.48	+48%
Africa	0.86	-	-	2020 ^a	1.10		+28%			4.06	+372%
Rest-of-the-world	1.20	-20%	-	1990 ^b	1.35		+12%			0.36	-70%
World	27.33	-	-	-	34.06	33.44	+25%	+22%		20.49	-25%

Notes ^a Reference case of IEA (2008b) in 2020. This figure only serves to define the series of quotas from 2025 to 2050.

^b Latin America (Rest of the world) takes into account Brazil's (Ukraine's) commitments. ^c Figure for the R2015 scenario. ^d Figure for the non-R2015 scenarios. Sources: WRI (2010a,b), IEA (2007a, 2008b, 2010a).

China, India, Russia, Latin America and the Rest of the world are also committed to reduce emissions by 2020. Each commitment is accounted for in the model by a constraint on the emissions volume in 2020. The commitments made by China and India (WRI 2010a) are expressed in the form of a decrease in CO₂ emissions per unit of GDP. These commitments therefore depend on the path followed by economic growth. As this is uncertain, the model takes account of the two possible objectives in 2020 for Chinese and Indian emissions.

For Africa, non-OECD Asia and Middle East (who have not made no commitment for 2020), the 2020 level of emissions in the IEA's (2008b) reference scenario is used as a starting point for calculating regional quotas from 2025 to 2050.

3.3 Special issues relating to calibration on a stochastic economic-growth scenario

The efficient labor (i.e., labor productivity⁹ multiplied by the population) is a key driver of economic growth in SMERGE. As a consequence, to calibrate the model on the stochastic economic-growth scenario described by Figure 1, we consider the same stochastic scenario for the growth rate of efficient labor. At equilibrium, this calibration yields regional economic growth rates that are very close - but not identical - to the targeted values. As a matter of fact, the gross domestic product of a region is not equal to the production of composite goods, principally because of intermediate consumption and the added value generated by the three other industrial sectors (electricity, non-electric energy and - especially in the Middle East - mining). The economic growth rate also depends - at least to a certain extent - on the availability of energy technologies and the environmental constraints specified in the model. In the version of SMERGE used here, the parameters reflecting Autonomous Energy Efficiency Improvement¹⁰ (AEEI) have been calibrated on an energy-intensity scenario that is consistent with EIA's (2010) projections.

More generally, let us stress that the joint maximization of all regional objective functions is intended to portray the market equilibrium consistent with a given (stochastic) view of the future. The choice of the corresponding parameters flows more from a descriptive than a prescriptive approach. Thus, the different regional rates of time preference for utility are chosen so as to respect economic-growth differentials between regions (corresponding to the calibration scenario). In fact, in the model, the perfect mobility of the composite good is equivalent to the perfect mobility of capital. Therefore, at equilibrium, all regional interest rates are equal. According to Ramsey rule (e.g. Durand-Lasserve et al. (2010)), the sum of the regional rate of time preference for utility and of the rate of growth in regional *per capita* consumption is therefore the same for all regions. If we consider that growth in regional *per capita* consumption and regional rate of economic growth are very close¹¹, this implies that the differential in economic growth between two regions is approximately equal to the difference between the two regional rates of time preference for utility. On this point, it is interesting to note that, in a rather unusual way, the stochastic economic-growth scenario adopted here leads us to consider regional rates of time preference for utility themselves to be stochastic (since the differentials in regional economic-growth rates depend on the branch of the stochastic scenario under consideration).

⁹ As emphasized by Jacoby et al. (2008), p.615, about CGE models, "it is well established that economic growth cannot be explained only by the growth of labor and accumulation of capital. A residual productivity factor always remains."... "this phenomenon conventionally is represented in one of two ways – either a change in total factor productivity or as an increase in labor productivity".

¹⁰ All sources of non-price-induced reductions in the energy required per unit composite good are summarized in MERGE by the AEEI parameters, which operate as scaling factors on the energy input into production. As Richels and Blanford (2008) stress, these reductions may occur due to both technological progress (e.g. end-use efficiency) and structural changes in the economy (e.g. shifts away from manufactured goods towards services).

¹¹ At the steady state of a stylised growth model in which the efficient labor grows at an exogenous rate, consumption and Gross Domestic Product both grow at this same rate (see for example Aghion and Howitt (1998) p. 22).

4. Results and interpretation

For a better understanding of the impact of the uncertainty surrounding economic recovery, the equilibrium of the model is determined for each of the following five values of the probability p : 1 (deterministic scenario with R2015 certain), 0.8, 0.5, 0.2, 0 (deterministic scenario with NR certain).

4.1 Achieved economic-growth scenarios

For the various values of p under consideration, the stochastic scenario for GDP growth obtained at equilibrium replicates relatively well the stochastic scenario of efficient labor used to calibrate the model. This is illustrated in Figure 3 for $p = 0.5$. The fact that GDP grows a little more than efficient labor during the initial periods is explained by the regional AEEIs. Energy expenditure actually rises less rapidly than the output of the final sector, even though the latter grows almost at the same rate as efficient labor. For all values of p , the economic growth differential between the high and low branches nevertheless remains at around 1%, in line with the desired stochastic scenario. In concrete terms, all the agents in the model form their expectations by considering the stochastic scenario of economic growth actually achieved at equilibrium.

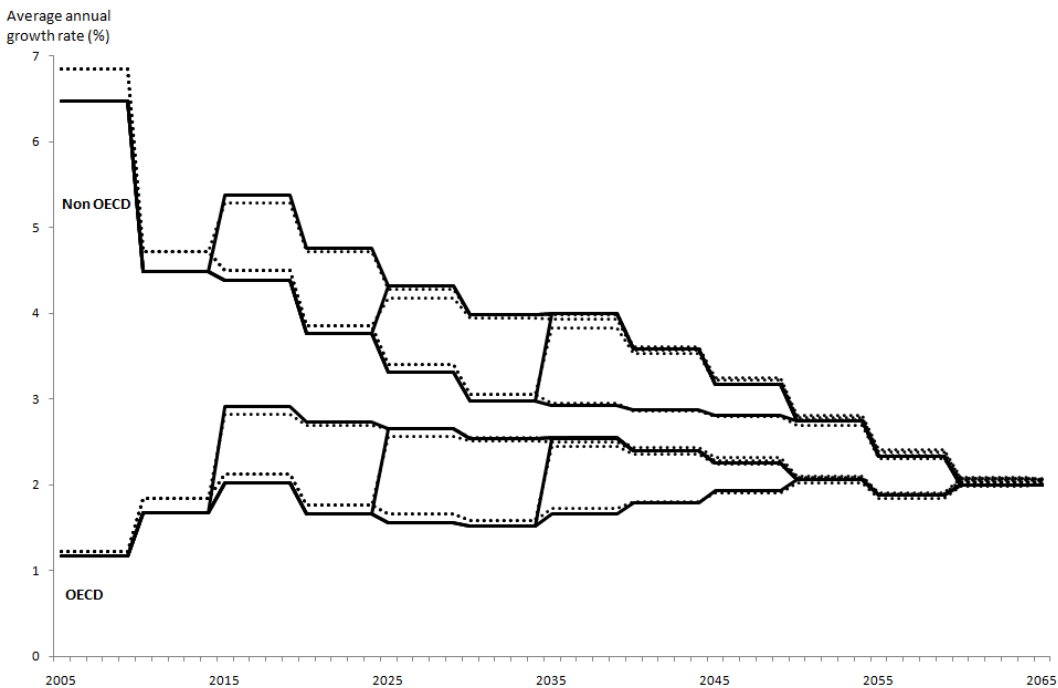


Figure 3: Efficient labor (plain lines) and achieved GDP growth (dotted lines) at equilibrium in OECD and non-OECD regions for $p = 0.5$

4.2 CO₂ price trajectories

Figure 4 shows the CO₂ prices in the European Union - corresponding to the global-market price from 2025 onwards - in the various scenarios. The CO₂ price appears to be very sensitive to the path

followed by economic growth, as well as to the agents' initial anticipations (i.e. the value of p). In 2010, the price per ton of CO₂ ranges between \$26 ($p=0$) and \$29 ($p=1$). According to the scenarios and branches under consideration, the price varies between \$35 ($p=0.5$) and \$65 ($p=0.2$) in 2020, between \$33 ($p=0.8$) and \$80 ($p=0.2$) in 2030, and between \$25 ($p=0.8$) and \$163 ($p=0.2$) in 2045. Let us note that in the case of no recovery (the NR branch), the CO₂ price in 2045 is extremely sensitive to initial anticipations: \$78 if non-recovery was perfectly anticipated ($p=0$), but \$25 if it was very poorly anticipated ($p=0.8$).

An essential difference exists between the R2015 and NR branches. In the R2015 branch, in terms of decision-making, the role of anticipations (i.e. the value of p) is limited to the 2010 and 2015 periods, since from 2020 onwards no uncertainty remains, with economic growth remaining high. On the other hand, in the NR branch, the uncertainty surrounding a possible economic recovery persists until 2035. Up to that date, during each period, the uncertainty consequently has two (opposite) effects on the CO₂ price: the effect resulting from past decisions taken in anticipation of a possible rapid recovery which in the end did not take place ("past precaution effect") and the effect of current decisions taken in anticipation of a possible future recovery ("current precaution effect"). The past (current) precaution effect leads to a current CO₂ price that goes lower as p gets higher (smaller).

This perspective may for example explain why, in the R2015 branch, the CO₂ prices obtained in the various scenarios converge quite rapidly (from 2025 onwards) towards neighbouring values, with the past precaution effect being limited to the decisions taken in 2010 and 2015. In the same way, the figures given in the previous paragraph show that the lowest CO₂ price (still drawn from the NR branch) is obtained overall for a probability that is higher the further away the date considered is. So, in 2010, the only thing that matters is the current precaution effect, which leads to less and less banking of emissions permits as the probability of a rapid recovery gets lower. The lowest price is thus obtained for $p=0$. However, when we move further away in time, the past precaution effect becomes more and more significant relative to the current precaution effect. In the NR branch in 2040, when there is no more uncertainty about the economic growth to come, only the past precaution effect has an impact on the CO₂ price, which is therefore at its lowest (\$21) when a rapid economic recovery has initially been considered highly probable ($p=0.8$).

In all scenarios, emissions permits are banked right from the initial periods. This banking connects the price of an emissions permit from one period to another, so that it then follows the Hotelling rule. In 2020, each of the two possible branches of the scenario yields specific emissions-permit price and interest rate (between 2015 and 2020). As a result, the price of an emissions permit in 2015 is equal to the expected value of its price in 2020 discounted at the corresponding interest rate.

In the R2015 branch, as one might expect, the rise in the emissions permit price is higher as the value of p gets lower, i.e. the economic recovery has been poorly anticipated. When $p=0.2$, the permits banked beforehand are used during the 2020 period to mitigate the shock on the CO₂ price. The price of an emissions permit is therefore \$65, compared to a price of \$47 when economic recovery has been anticipated perfectly ($p=1$). This impact is nevertheless transitory, both because the energy system adapts and because of the "hot air" generated by non-OECD countries entering the global cap-and-trade market in 2025 (with Chinese and Indian emissions quotas higher in the R2015

branch). Thus, in the R2015 branch of the $p=0.2$ scenario, during the 2025 period the European Union buys on average 287 million emissions permits per year (8.8% of its total emissions).

Conversely, the absence of economic recovery, whereas such a recovery had been considered probable, leads to a lower emissions-permit price in 2020. This pattern—impact on the permit price if the realized path (economic recovery occurring or not) was initially poorly anticipated—is repeated in 2030 and 2040. Finally, when the absence of economic recovery was anticipated perfectly ($p=0$), the CO₂ price is lower in 2025 than in 2020, which leads to all the previously banked permits being consumed in 2020.

When the economic recovery is initially seen as fairly probable ($p \geq 0.5$), the European energy system prepares itself relatively well. This enables continued banking of emissions permits in 2020, with the permit price rising at the interest rate between 2020 and 2025. In fact, where $p \geq 0.5$, all OECD regions bank emissions permits, which, by backward induction (through the Hotelling rule) from a single global emissions-permit price in 2025, leads to a convergence of CO₂ prices in the various regional markets from 2015 onwards.

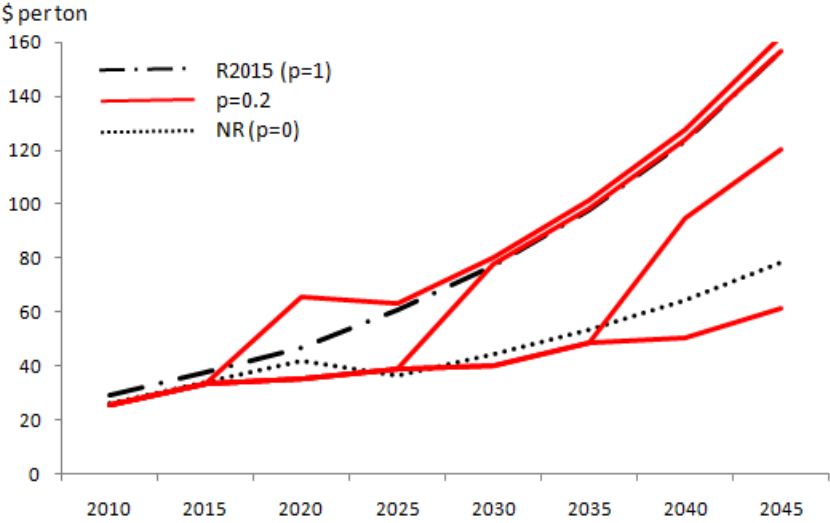


Figure 4a

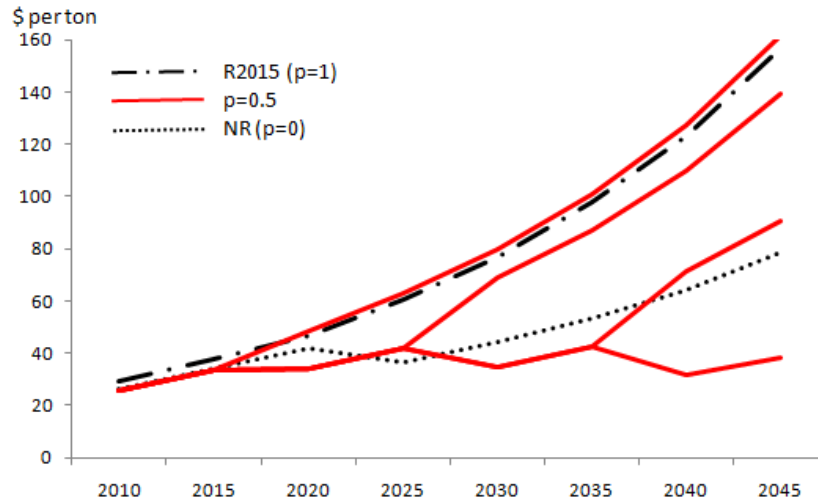


Figure 4b

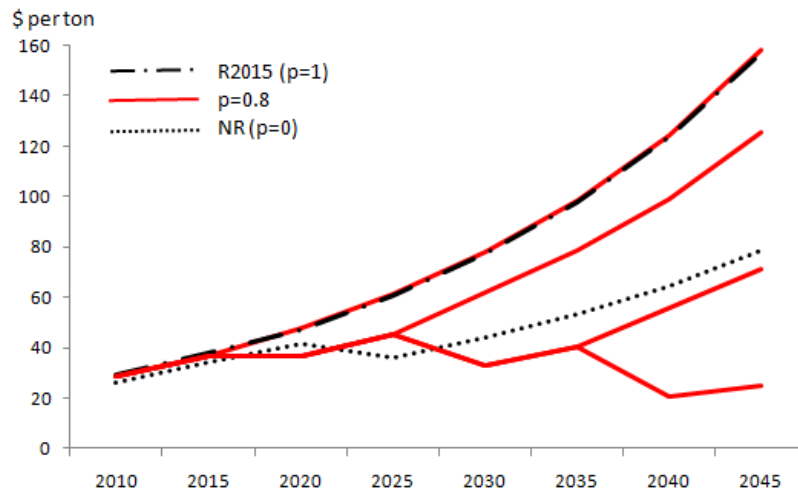


Figure 4c

Figure 4: Trajectories of CO₂ price in the European Union in the various scenarios

4.3 Technological trajectories

Figure 5a shows the world installed capacities for each power technology in the R2015 branch when economic recovery is either perfectly ($p=1$), or badly ($p=0.2$) anticipated. Figure 5b shows the installed capacities in the NR branch when non-recovery is perfectly ($p=0$) or badly ($p=0.8$) anticipated. In all cases, the development of the global electric system is fairly similar during the initial periods. The regional emissions targets are so ambitious that, regardless of anticipations on economic growth, the constraints limiting the expansion of some renewables are binding from the earliest periods (so as to enable subsequent large-scale deployment).

From 2030, hydropower stagnates due to exogenous availability constraints. The share of nuclear in power generation capacity increases from 9% in 2005 to between 11% and 16% in 2045. The steep rise in gas-fired capacity between periods 2005 and 2010 is mainly explained by the substitution of gas for coal in OECD regions so as to limit their emissions. At the same time, the rise in coal-based production capacity is driven by non-OECD regions (which are not yet subject to emissions constraints). Fossil-fuel-based capacities without CCS decrease from 2015, i.e. when renewables, especially wind and biomass, have reached sufficient size to expand widely. The R2015 and NR branches diverge significantly from 2030 onwards, especially for nuclear, renewables and CCS.

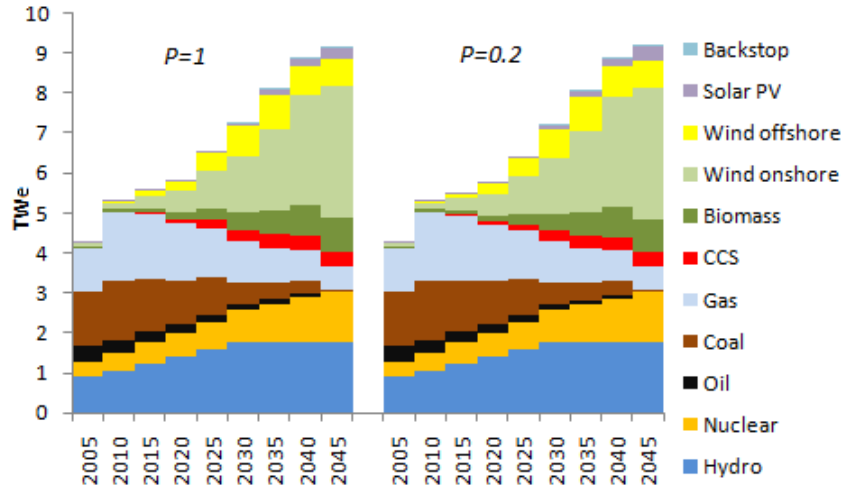


Figure 5a: Power production capacity in the R2015 branch for $p=1$ and $p=0.2$

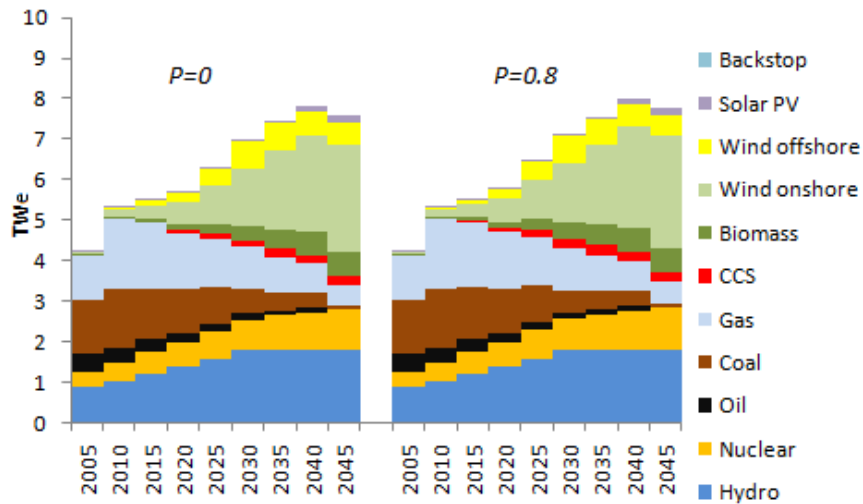


Figure 5b: Power production capacity in the NR branch for $p=0$ and $p=0.8$

The relatively low installed CCS capacity inaccurately reflects the significant role of CCS in the energy mix from 2025 onwards, because of its high load factor of 85% (especially relative to 18-40% for wind) as shown in Table 1. Furthermore, as illustrated by Figure 6, the deployment of CCS is

highly sensitive both to the path actually followed by growth and to agents' initial anticipations. In the scenario where recovery and non-recovery in 2015 are equally probable ($p=0.5$), the installed CCS capacity is 165 GW in 2025. This capacity is only 106 GW when non-recovery has been perfectly anticipated ($p=0$). This sensitivity of CCS deployment to anticipations on economic growth is in particular due to its time-to-build of two periods.

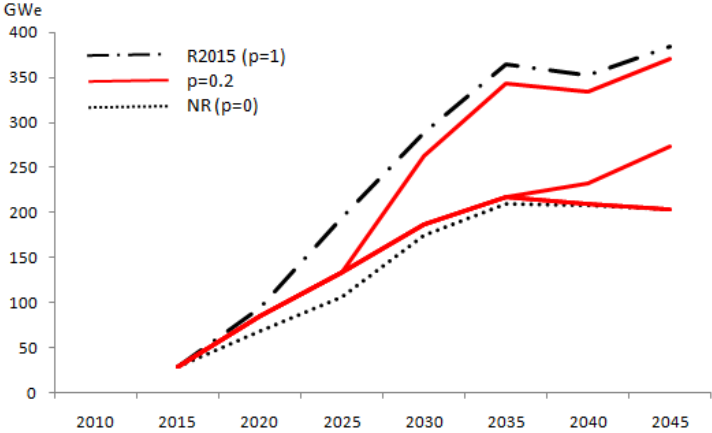


Figure 6a

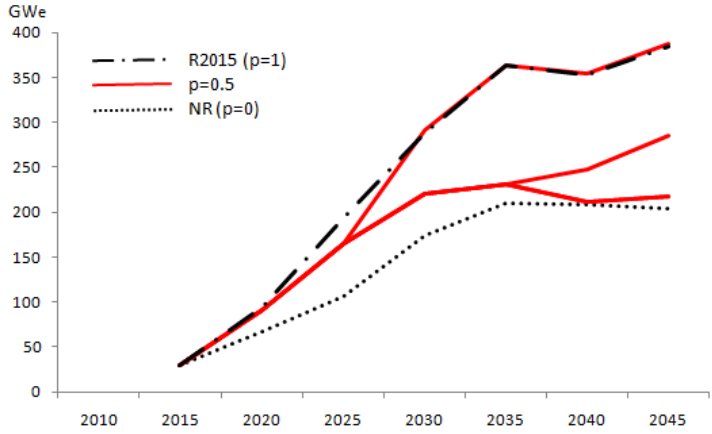


Figure 6b

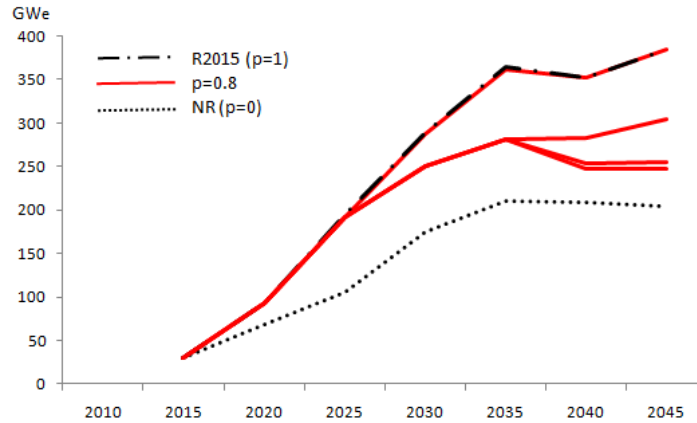


Figure 6c

Figure 6: World installed power generation capacity with CCS in the various scenarios.

Finally, the adaptation of the energy mix results not only from investment in low-CO₂ technologies, but also from adjusting the use of existing fossil-fuel-based capacities. In the first periods, this latter mechanism is a decisive factor in the sensitivity of CO₂ prices to anticipations on economic growth. It also largely explains the electricity prices yielded by the model.

4.4 Marginal technologies and electricity prices

Electricity prices in the European Union are shown in Figure 7 for the various stochastic scenarios considered. Figure 7 also indicates the marginal technology in each period, i.e. the technology whose short-run marginal cost of production is equal to the price of electricity. This short-run marginal cost takes account of variable operating costs, including fuel and CO₂ emissions permits. The marginal technology is characterized by partial use of available capacity.

In some cases, this short-run marginal cost is degenerate, with a left-hand short-run marginal cost (corresponding to the technology used to produce the last kWh and whose production capacity is fully used) and a right-hand short-run marginal cost (corresponding to the technology currently not used, but which would be used to produce one additional kWh). The price of electricity given by the model therefore falls between these two marginal costs, with the corresponding symbols being represented side by side in Figure 7. Agents in the model base their decisions on this price that, at equilibrium, ensures the clearing of the power market.

The sequence of marginal technologies demonstrates that the various types of CO₂-emitting technologies are successively abandoned as the emissions-permit price rises. In general, from 2010 to (in some branches) 2025, remaining coal-fired power plants are only partially used. Subsequently, these plants are no longer used, with remaining gas-fired plants then representing the marginal technology. After that, from 2030 (2025 in the R2015 branch of the scenario $p=0.2$), with remaining gas-fired plants no longer being used, electricity-production adjustment occurs through the use of new gas-fired capacities (even though this was installed after 2010). From 2040, or even 2035, the new gas-fired plants are no longer in use. Renewables and nuclear, with a low short-run marginal cost, are used at full capacity (a situation denoted by a cross and a circle side by side in Figure 7). In

the case of an absence of economic recovery that has been correctly anticipated ($p=0, 0.2$), the abandonment of the technologies based on fossil fuels occurs earlier (2035 instead of 2040). This is in particular due to lower investment in the final sector leading to lower demand for electricity in 2035. The achievement of a mix of power-generation technologies emitting little or no CO₂ is therefore not contingent upon the realization – or the anticipation – of strong economic growth. On the contrary, strong growth may, by driving up energy demand, cause standard fossil-fuel-based capacities to be used for a longer time. As we can see from Figure 7, the stronger the economic growth, the higher the electricity price.

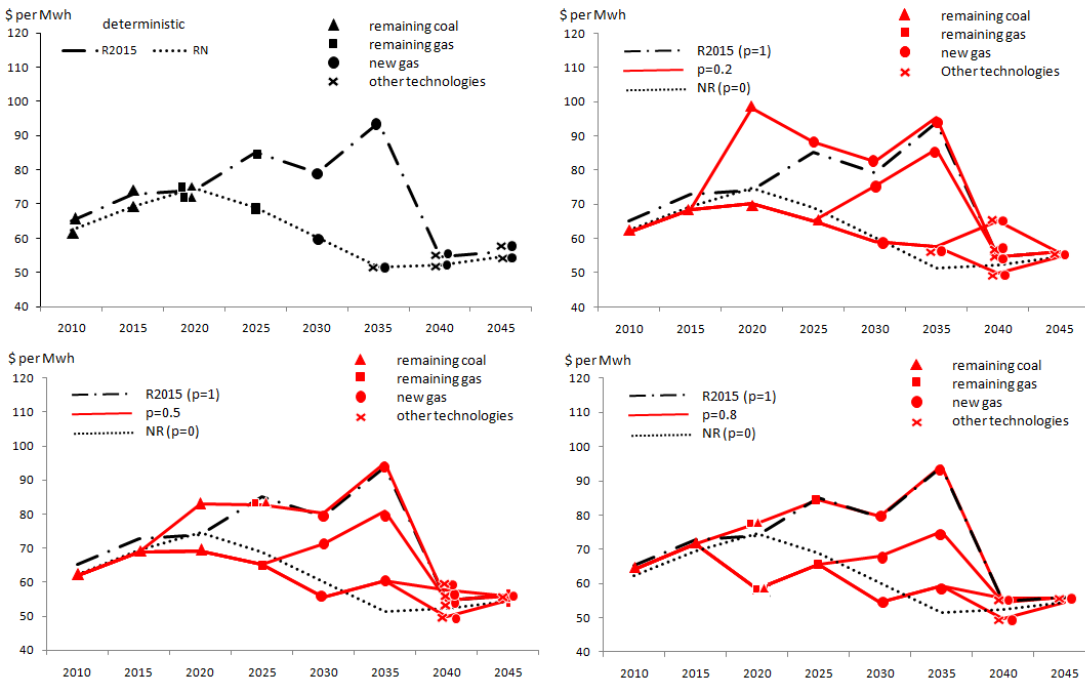


Figure 7: Trajectories of electricity price in the European Union in the various scenarios.

Moreover, incorrect anticipations of economic growth may lead to situations of over- or under-investment, possibly with a strong impact on the electricity price. A poorly anticipated economic recovery in 2015 ($p=0.2$ and, to a lesser extent, $p=0.5$) leads to an abrupt rise in the price of electricity in 2020 (up to \$98 per MWh). Inadequate investment in new gas-fired plants and renewables requires the use of some old coal-fired power plants whose short-run marginal production cost is extremely high because of the CO₂ price. The electricity price subsequently decreases, as investments in renewables enables the further use of the old coal-fired plants to be avoided. In the $p=0.2$ scenario, even old gas-fired plants are abandoned through the combined effect of high gas and CO₂ prices. In this way we move directly from a price in 2020 set by the short-run marginal cost of remaining coal-fired plants to a price in 2025 set by the short-run marginal cost of new gas-fired plants.

Conversely, a strongly-anticipated recovery that does not take place may give rise to an overinvestment situation: anticipating (wrongly) an economic recovery leads to premature investments in gas and renewables. As this recovery does not happen, the gas-fired capacities are sufficient to allow the remaining coal-fired power plants to be abandoned, as we observe in 2020 in the NR branch of the $p=0.8$ scenario. As a result of the low CO_2 and gas prices in this branch (see Figures 4 and 8), the electricity price drops to a particularly low level.

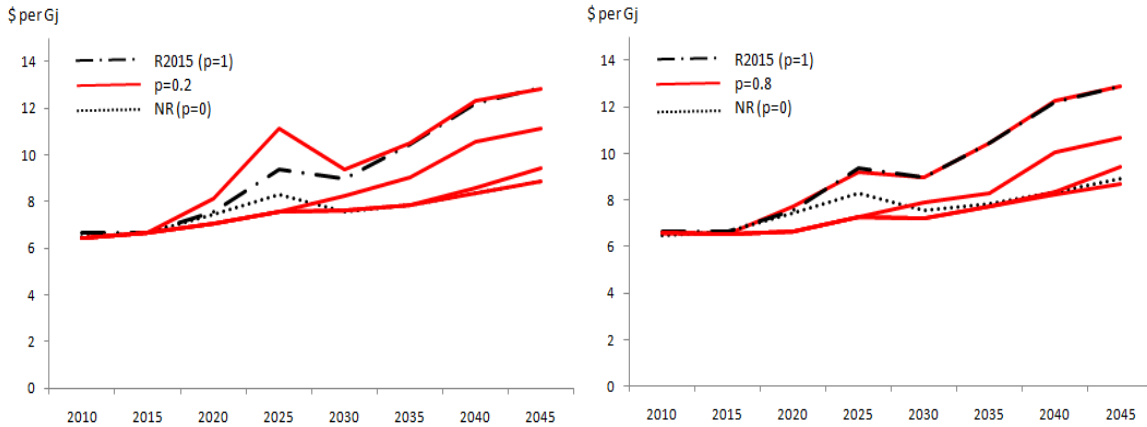


Figure 8: Gas price in the European Union in the $p = 0, 0.2, 0.8, 1$ scenarios.

4.5 Endogenous investment costs and net present values in the electricity sector

At the optimum of social welfare in each region, the optimality conditions of the model can be interpreted as if a single power utility - acting as price taker and providing all electricity production in the region - were to maximize its value while taking account of the constraints limiting the expansion rate of each technology, the market shares of wind, nuclear and solar technologies, and the availability of hydropower and biomass.

Let us consider a given technology. Table 1 provides an exogenous investment cost, based on EIA (2010a,b) estimates, which, when used in the model, should be interpreted as the cost of construction and installation for a power-generation equipment manufacturer. By charging the power utility a price equal to this exogenous cost, an equipment manufacturer makes no profits. At a regional scale, equipment manufacturers form a technological sector whose expansion is constrained. The Appendix shows that the model internalizes the constraints limiting the expansion rate of this technological sector into the investment cost paid by the power utility. The resulting endogenous cost may be interpreted as the price actually paid (to the equipment manufacturer) by the power utility for installing an additional unit of capacity. This price is equal to the exogenous investment cost adjusted for the dual variables associated with the expansion constraints. This investment-cost adjustment may be interpreted as resulting from tensions between demand for additional capacity (from the power utility) and supply of new capacity (by the technological sector under consideration). From an economic point of view, the expansion constraints generate an inelasticity of supply (through bottlenecks) by the technological sector. At equilibrium, this can lead to a rise in the price paid by the power utility for the acquisition of new production capacity.

Figure 9 shows the endogenous investment cost (determined using the equations in the Appendix) of wind onshore and wind offshore technologies in the European Union, North America and China. In each region and for each technology, the maximum annual growth rate in installed capacity is 10%. The endogenous investment cost is higher than the exogenous investment cost until 2025 in Europe and until 2030 in North America. During this lapse of time, the growth in demand for electricity, especially carbon-free electricity, comes up against bottlenecks in the supply of new capacities using these two technologies. After 2030, the expansion constraints have no further effects, because of the maturity of both technological sectors and - in a context of low growth in electricity demand - the limitation on the market share of wind power. In the European Union, where growth in demand for electricity is lower, the constraint on market share of wind becomes binding sooner than in North America. The endogenous investment cost - highly sensitive to the path followed by economic growth in North America - depends only very slightly on initial anticipations.

In China, the curves of endogenous investment costs are all bubble-shaped¹² centred on 2025, a period which corresponds to this region’s entry to the global emissions-permit market. The bottleneck in the wind equipment sectors is very significant at that date. In a context of steeply rising demand for electricity, the price of acquiring production capacity is relatively sensitive to the path of economic growth followed, and, to some extent, to agents’ initial anticipations. Interestingly, in 2015 the endogenous investment cost for wind offshore is lower than the exogenous cost. Chinese manufacturers therefore agree to sell below construction cost temporarily, so as to develop manufacturing capacity and produce more equipment subsequently (when the endogenous investment cost is considerably higher than the exogenous cost). An alternative interpretation is that, from a social point of view, the Chinese authorities should subsidize this technological sector in 2015.

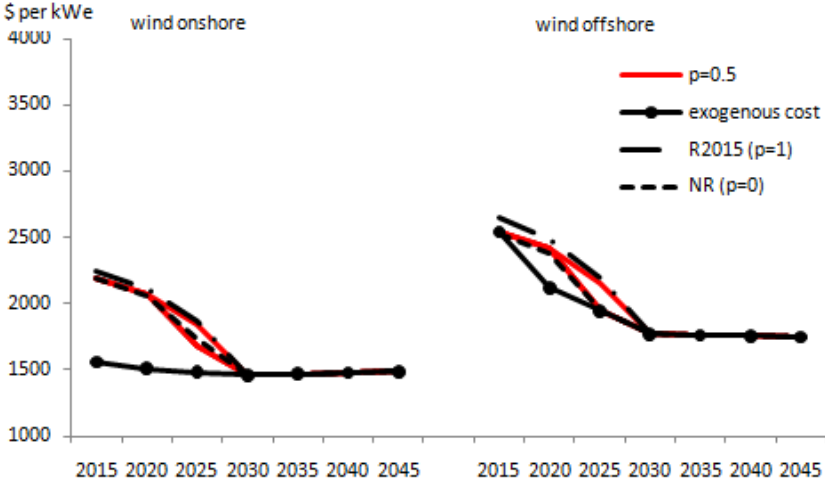


Figure 9a: European Union

¹² By analogy, in North America and the European Union (regions subject to an emissions-permit market right from the first periods), the endogenous investment costs curves may be seen as bubbles truncated on the left.

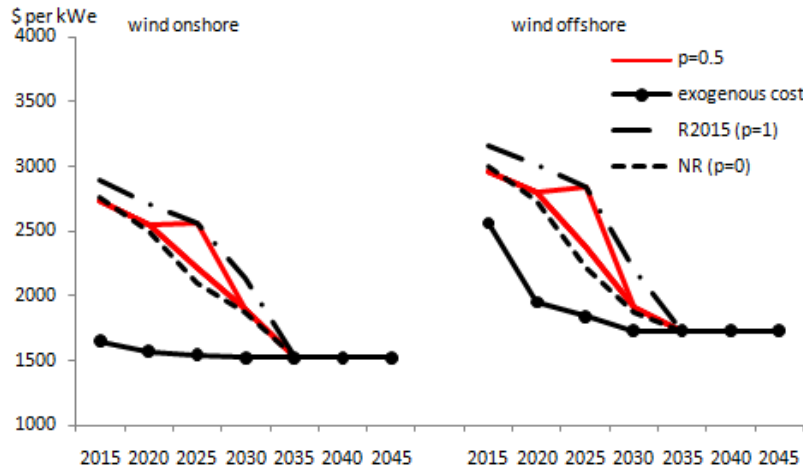


Figure 9b: North America

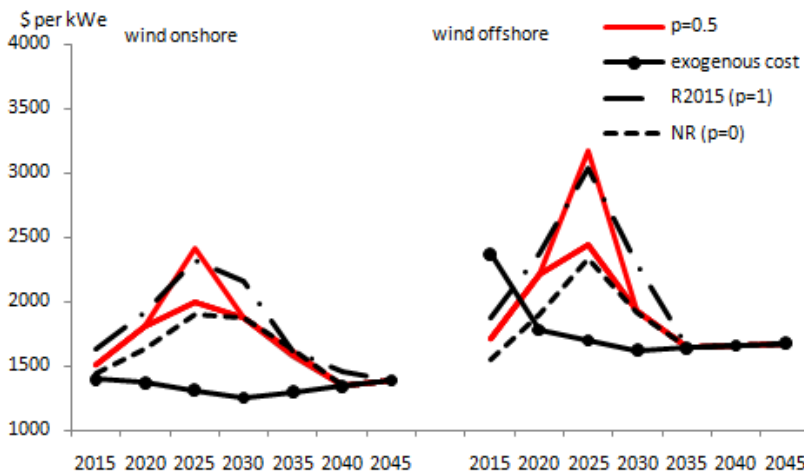


Figure 9c: China

Figure 9: Endogenous investment costs of wind onshore and wind offshore technologies in scenarios $p = 0, 0.5, 1$.

From the results of the model, we can determine the expected net present value of a marginal investment by considering the endogenous investment cost, the electricity price trajectories, fixed and variable production costs and the decay rate of the installed capacity. The cash flow achieved in each possible state of the world is discounted at the economy's interest rate realized in that state of the world. The expected net present value, determined as the expected sum of these discounted cash flows, reflects the point of view of a power utility that would make the investment in an atomistic electricity sector. This utility would effectively consider that its investment decisions had no effect on the breakdown between technologies (i.e. maximum market shares). Table 3 shows the expected net present values (as percentages of the corresponding endogenous investment costs) associated

with wind onshore and wind offshore production capacity built during the 2015 and 2020 periods in China, North America and the European Union. In China, these expected net present values are relatively close to zero. On the other hand, they are relatively high in European Union and North America, as the constraints on market share for wind power are fairly soon binding, which generates a scarcity rent at the level of both technologies. Thus, if we assume that a (maximum) market share of 50% (instead of 33%) for wind power is technically realistic, the net present values obtained in both deterministic scenarios are all below 8% (12%) of the corresponding endogenous investment cost in 2015 (2020). Furthermore, Table 3 shows that anticipation of a rapid economic recovery does not necessarily result in a markedly higher net present value.

In practice, the valuation of an investment by a private utility differs noticeably from the above calculation. Thus, the model does not consider any fiscal transfer. Moreover, private firms generally use higher discount rates than that used by the public authorities. Let us consider, for example, the case of a deterministic economic recovery ($p = 1$), taking into account a tax rate of 30% and linear depreciation of the investment over 10 years (2 periods) for calculating the project's free cash flows. An investment in wind onshore (wind offshore) in 2015 in the European Union would then generate an internal rate of return of 5.9% (6.1%). This internal rate of return would be 7.3% (7.7%) for an investment in wind onshore (wind offshore) in 2020. Without subsidies, a firm using a discount rate greater than 8% (in real terms) would therefore not make these investments.

Table 3: Expected net present value as a percentage of endogenous investment cost for marginal investment made in 2015 and 2020.

		2015					2020				
		$p=0$	$p=0.2$	$p=0.5$	$p=0.8$	$p=1$	$p=0$	$p=0.2$	$p=0.5$	$p=0.8$	$p=1$
European Union	Wind onshore	16	20	23	25	25	24	31	35	38	39
	Wind offshore	18	23	26	27	28	27	34	38	41	42
North America	Wind onshore	10	10	9	7	6	24	25	21	20	19
	Wind offshore	13	13	11	9	9	27	28	24	23	22
China	Wind onshore	-2	-5	-1	-6	-7	6	4	2	0	-1
	Wind offshore	1	-3	1	-3	-4	8	4	4	2	1

6. Conclusion

Both economic-growth path realized and agents' initial anticipations strongly influence the CO₂ price. Thus, in 2040, the global price of CO₂ may range from \$21 (when an initially-anticipated economic recovery never occurs) to \$128 (in case of non-anticipated rapid economic recovery).

A rapid and poorly-anticipated economic recovery may cause an abrupt (but transient) rise in the CO₂ price because of an insufficient number of banked permits and, to a lesser degree, unsuitable technologies.

The case of no economic recovery whereas a rapid upturn had been considered possible is ambiguous. The uncertainty in this case has two opposite effects on the CO₂ price: the existence of a stock of emissions permits previously banked in anticipation of a possible rapid economic recovery which in the end did not take place, and the need for a sufficient stock of banked permits in anticipation of a possible future recovery. As time goes by, the effect of past banking becomes preponderant, which leads in the long term to very low CO₂ price levels.

During the initial periods of the model, the differences in the quantities of emissions permits banked observed between the different scenarios result principally from adjustments in the use of existing fossil-fuel-based capacities. Anticipating economic recovery (and therefore higher CO₂ prices) as being probable speeds decommissioning, first of remaining coal-fired power plants, then of remaining gas-fired power plants, and finally of more recent gas-fired power plants. Additionally, the deployment of CCS technologies is especially sensitive to anticipations.

In the electricity sector, the model internalizes the constraints limiting the expansion rate of each technology into the price paid by the power utility for acquiring additional production capacities. For the wind onshore and wind offshore technologies, this endogenous investment cost – which is relatively sensitive to the realized economic growth - in general depends very little on initial anticipations. In the medium run, assuming a technical limitation on wind-power market share creates a rent for power utilities producing with offshore and onshore wind. From the viewpoint of a private utility paying an income tax, a marginal investment made before 2020 nevertheless yields an internal rate of return that is noticeably lower than 8%. A subsidy from the public authorities would therefore be justified to attain the socially optimal level of investment. To a certain extent, a power utility investing in wind power would today receive public subsidies and, in the future, benefit from a scarcity rent priced by the market.

References

- Aghion, P., and P. Howitt (1998). *Endogenous growth theory*. Cambridge: The MIT Press.
- Bosetti, V. and M. Tavoni (2009). “Uncertain R&D, backstop technology and GHGs stabilization.” *Energy Economics* 31 (Suppl.), S18–S26.
- Bosetti, V., Carraro C., Sgobbi, A. and M. Tavoni (2009). “Delayed action and uncertain targets. How much will climate policy cost?” *Climatic Change* 96 (3), 299-312.
- De Cian, E. and M. Tavoni (2010). “Hedging against climate policy and technology uncertainty: implications for technology mix and policy instrument choice.” *Proceedings of International Energy Workshop*, Stockholm, July 2010.
- Durand-Lasserve, O., Pierru, A. And Y. Smeers (2010). “Uncertain long-run emissions targets, CO₂ price and global energy transition: a general equilibrium approach.” *Energy Policy* 38 (9), 5108-5122.
- EIA (2010). *International Energy Outlook 2010*. U.S. Energy Information Administration, www.eia.gov/oiaf/ieo/index.html.
- Hayashi, F. and E. C. Prescott (2002). “The 1990s in Japan: a lost decade.” *Review of Economic Dynamics* 5 (1), 206-235.
- IEA (2010a). *World Energy Outlook 2010*. International Energy Agency, Paris.
- IEA (2010b). *Projected Costs of generating Electricity 2010*. International Energy Agency, Paris.
- IEA (2008a). *Energy Technology Perspectives*. International Energy Agency, Paris.
- IEA (2008b). *World Energy Outlook 2008*. International Energy Agency, Paris.
- IEA (2007a). *World Energy Outlook 2007*. International Energy Agency, Paris.
- Jacoby, H. D., Reilly J. M., McFarland J. R., and S. Paltsev (2006). “Technology and Technical change in the MIT EPPA model.” *Energy Economics* 28 (5-6), 610-631.

- Köhler, J., Grubb, M., Popp D., and O. Edenhofer (2006). "The transition to endogenous technical change in climate-economy models: A technical overview to the Innovation Modelling Comparison Project". The Energy Journal. Endogenous Technological Change and the Economics of Atmospheric Stabilisation, Special Issue, 17-56.
- Könnölä T., Carrillo-Hermosilla, J., and R. van der Have (2008). "System transition concepts and framework for analysing energy system research and governance." IE WP08-31. Available at SSRN: <http://ssrn.com/abstract=1646274>.
- Manne, A. S., and T.R. Olsen (1996). "Green house gas abatement - toward pareto-optimal decisions under uncertainty." Annals of Operation Research 68 (2), 267–279.
- Manne, A. S., Mendelsohn, R., and R.G. Richels (1995). "MERGE: a model for evaluating regional and global effects of GHG reduction policies". Energy Policy 23 (1), 17–34.
- Manne A. S. and R. G. Richels (1995). "The greenhouse debate: economic efficiency, burden sharing and hedging strategies". Energy Journal 16(4), 1–37.
- Meeraus, A., and T. Rutherford (2005). *Mixed complementarity formulations of stochastic equilibrium models with recourse*. GOR Workshop, Bad Honnef (Germany), October 20–21.
- OCDE (2010), Economic outlook 2010. OECD, Paris.
- Rafaj, P., and S. Kypreos (2007). "Internalisation of external cost in the power generation sector: Analysis with Global Multi-regional MARKAL model." Energy Policy 35 (2), 828–843
- Richels, R. G., and G. J. Blanford (2008). "The value of technological advance in decarbonizing the U.S. economy." Energy Economics 30 (6), 2930-2946.
- Scott, M.J., Sands, R. D., Edmonds J., Liebetrau, A. M. and D.W. Engel (1999). "Uncertainty in integrated assessment models: modeling with MiniCAM 1.0". Energy Policy 27 (14), 855-879.
- Webster, M. D., Paltsev, S., Parsons, J., Reilly, J. and H. Jacoby (2008). *Uncertainty in Greenhouse Emissions and Costs of Atmospheric Stabilization*. MIT Joint Program Report No 165, MIT Joint Program on the Science and Policy of Global Climate Change, Cambridge, MA.
- WRI (2010a). *Summary of GHG reduction pledges put forward by developing countries*. World Resources Institute, June 2010.
- WRI (2010b). *Comparability of annex I emission reduction pledges*. World Resources Institute, February 2010.

Appendix: Constraints on expansion rate and endogenous investment costs

Let us consider a given power-generation technology in a given region. Like renewables in the model, this technology is supposed to have a low short-run marginal cost, with the capacity installed in the region therefore being entirely used during each period. At the optimum of the regional social welfare, the optimality conditions of the model can be interpreted as if a price-taking regional power utility were maximizing the expected net present value generated by its policy of investment in the technology considered. In a consistent manner, we here directly consider the (decentralized) power utility's value-maximization problem.

To alleviate the notations, only one probability node is here considered. An uncertainty is thus resolved between periods $t-1$ and t , with two possible states from period t onwards (for example, economic recovery and absence of economic recovery from 2020). Each state s has a probability of occurrence denoted by p^s . Where necessary, each variable or coefficient is indexed as a function of time (subscript) and state (superscript). The power utility therefore maximizes the program below, with the dual variable associated with each constraint appearing in parentheses to the right of the constraint:

$$\begin{aligned} \text{Max} & \left(\sum_{j=1}^{t-1} z_j (a_j k_j - c_j i_{j-1}) + \sum_{s=1}^2 p^s \left(z_t^s (a_t^s k_t - c_t i_{t-1}^s) + \sum_{j=t+1}^T z_j^s (a_j^s k_j^s - c_j i_{j-1}^s) \right) \right) \\ \text{s.t.} & \begin{cases} (1+g)k_{j-1} - k_j \geq 0 & (\alpha_j) \quad 1 \leq j \leq t \\ i_{j-1} - k_j + (1-d)k_{j-1} = 0 & (\lambda_j) \quad 1 \leq j \leq t \\ (1+g)k_t - k_{t+1}^s \geq 0 & (\alpha_{t+1}^s) \quad s=1,2 \\ i_t^s - k_{t+1}^s + (1-d)k_t = 0 & (\lambda_{t+1}^s) \quad s=1,2 \\ (1+g)k_{j-1}^s - k_j^s \geq 0 & (\alpha_j^s) \quad t+2 \leq j \leq T, s=1,2 \\ i_{j-1}^s - k_j^s + (1-d)k_{j-1}^s = 0 & (\lambda_j^s) \quad t+2 \leq j \leq T, s=1,2 \end{cases} \end{aligned}$$

The coefficient a_j represents the operating cash flow generated in period j by the use of one kW of installed power. This coefficient takes account of the regional electricity price and operating costs. The coefficient c_j represents the cost of construction and installation - by the technological sector considered - of one kW of power-generation capacity in period j . It corresponds to the exogenous investment cost given in Table 1. The capacity built in period j (assumed to be positive) is decided in period $j-1$ and is denoted by i_{j-1} . The total installed capacity owned by the power utility in period j is denoted by k_j , with k_0 being fixed. Because of the expansion constraints, the growth rate in this installed capacity from one period to another cannot exceed g . In addition, the installed capacity decays at the periodic rate d . The present value of a cash flow generated in period j is obtained by applying the discount factor z_j (derived from the economy's interest rate in the model) to this cash flow.

By differentiating the Lagrangian of this problem with respect to k_T^s and i_{T-1}^s , we obtain:

$$p_s z_T^s a_T^s - \alpha_T^s - \lambda_{T-1}^s = 0$$

$$\lambda_T^s - p^s z_T^s c_T = 0$$

By combining these two equations, we have:

$$a_T^s = c_T + \frac{\alpha_T^s}{p^s z_T^s} \quad (1)$$

At optimum, in period T (2100 in the model), a marginal investment generates a zero net present value: the present value of the expected operating cash flows (here summed up as α_T^s) is equal to the investment cost. According to (1), the power utility therefore considers that, in state s , installing at period T one additional kW of capacity costs $c_T + \frac{\alpha_T^s}{p^s z_T^s}$.

Let us now differentiate the Lagrangian with respect to k_j^s and i_{j-1}^s , with $t+1 \leq j \leq T$:

$$p^s z_j^s a_j^s + (1+g)\alpha_{j+1}^s - \alpha_j^s + (1-d)\lambda_{j+1}^s - \lambda_j^s = 0 \quad (2)$$

$$\lambda_j^s = p^s z_j^s c_j \quad (3)$$

Combining (2) and (3), we obtain:

$$a_j^s = \frac{\alpha_j^s - (1+g)\alpha_{j+1}^s}{p^s z_j^s} + c_j - (1-d)\frac{z_{j+1}^s}{z_j^s} c_{j+1} \quad (4)$$

Let us define \bar{c}_j^s such that:

$$\bar{c}_j^s = c_j + e_j^s \quad (5)$$

$$\text{with: } e_j^s = \frac{\alpha_j^s - (1+g)\alpha_{j+1}^s}{p^s z_j^s} + (1-d)\frac{z_{j+1}^s}{z_j^s} e_{j+1}^s,$$

$$e_T^s = \frac{\alpha_T^s}{p^s z_T^s}.$$

Combining (5) and (4), we obtain:

$$a_j^s = \bar{c}_j^s - (1-d)\frac{z_{j+1}^s}{z_j^s} \bar{c}_{j+1}^s \quad (6)$$

Equation (6) enables us to interpret \bar{c}_j^s as an investment cost derived endogenously from the model. Anticipating the installation of $1-d$ kW of capacity by one period (i.e., installing 1 kW in period j instead of $1-d$ kW in period $j+1$) enables, through production during period j , generation of the additional operating cash flow a_j^s . However, advancing this installation from period $j+1$ to period

j generates an additional investment cost equal to $\bar{c}_j^s - (1-d)\frac{z_{j+1}^s}{z_j^s} \bar{c}_{j+1}^s$. Equation (6) simply indicates

that, at optimum, anticipating (or delaying) this marginal investment by one period does not modify the value of the objective function. We may also note that, formally, equation (6) corresponds to equation (4) written without the term containing the dual variables associated with expansion constraints (since the endogenous investment cost internalizes these constraints).

By recurrence we obtain:

$$e_j^s = \frac{1}{p^s z_j^s} \left(\alpha_j^s - (g+d) \sum_{k=j+1}^T \alpha_k^s (1-d)^{k-j-1} \right)$$

In state s , the endogenous investment cost is therefore (with $t+1 \leq j \leq T$):

$$\bar{c}_j^s = c_j + \frac{1}{p^s z_j^s} \left(\alpha_j^s - (g+d) \sum_{k=j+1}^T \alpha_k^s (1-d)^{k-j-1} \right) \quad (7)$$

By differentiating the Lagrangian with respect to k_t , i_{t-1} and i_t^s , we have:

$$-\alpha_t - \lambda_t + \sum_{s=1}^2 \left(p^s z_t^s a_t^s + (1-d) \lambda_{t+1}^s + (1+g) \alpha_{t+1}^s \right) = 0$$

$$\lambda_t = c_t \sum_{s=1}^2 p_s z_t^s$$

$$\lambda_{t+1}^s = P^s z_{t+1}^s c_{t+1}$$

Combining these equations, we obtain:

$$\sum_{s=1}^2 p^s z_t^s a_t^s = c_t \sum_{s=1}^2 p_s z_t^s + \alpha_t - (1+g) \sum_{s=1}^2 \alpha_{t+1}^s - (1-d) c_{t+1} \sum_{s=1}^2 p^s z_{t+1}^s \quad (8)$$

As the decision to invest was taken one period before, the endogenous investment cost \bar{c}_t is considered to be independent of the state realized in period t (since it was set in period $t-1$ when the order for capacity construction was issued). At optimum, the expected gain obtained by advancing by one period (i.e. in t rather than $t+1$) the installation of $1-d$ kW of capacity should be equal to the expected additional investment cost resulting from this decision. The endogenous investment cost \bar{c}_t must therefore satisfy the following condition:

$$\sum_{s=1}^2 p^s z_t^s a_t^s = \bar{c}_t \sum_{s=1}^2 p^s z_t^s - (1-d) \sum_{s=1}^2 p^s z_{t+1}^s \bar{c}_{t+1}^s \quad (9)$$

Combining (8) and (9), we obtain:

$$\bar{c}_t = c_t + e_t = c_t + \frac{\alpha_t - (1+g) \sum_{s=1}^2 \alpha_{t+1}^s + (1-d) \sum_{s=1}^2 p^s z_{t+1}^s e_{t+1}^s}{\sum_{s=1}^2 p^s z_t^s} \quad (10)$$

Following the same line of reasoning as before, for $1 \leq j \leq t-1$ we have:

$$\bar{c}_j = c_j + e_j$$

where: $e_j = \frac{\alpha_j - (1+g) \alpha_{j+1} + (1-d) z_{j+1} e_{j+1}}{z_j}$.

Using the values of the dual variables at the model's equilibrium, the endogenous investment cost can be backwardly computed with Equations (1), (5) and (10).