***Disaggregating the electricity sector in a CGE model and using imperfect competition to explain the introduction of new technologies to the sector***

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***Abstract***

The electricity sector in most CGE models is highly aggregate often represented by only a single aggregate production function. Improvement to this approach involves disaggregating the sector into various technological components represented by different production functions using ‘bottom-up’ information and then re-aggregated into a ‘top-down’ sector again using a similarly aggregate production function (CRESH, Logit). In this paper, we provide an alternative approach to this aggregation of technologies into a sector output by relying on the theory of perfect or imperfect competition between the different players in the market using these different technologies to arrive at an equilibrium position for the market. The paper illustrates the applicability of the new methodology with an example of the case of Japan where it is assumed that a climate policy is to seek to reduce CO2 emissions from fossil fuel technologies but a competing energy policy may also be pursued which seeks to reduce reliance on nuclear electricity following the accidents at the Fukushima nuclear power plants. The model illustrate how interactions between the technologies can lead to different outcomes depending on the extent of the competition (or lack of it) between the different players in the electricity market using these different technologies.

*Keywords:* Renewable and nuclear electricity supply, imperfect competition in CGE model, climate and energy policies.

1. **Introduction**

Climate and energy policies often have different (even though complementary) objectives and using different policy instruments to achieve these objectives. In the electricity sector, for example, the objective of climate policy is to reduce the level of CO2 emissions from the use of fossil-fuels in electricity generation while the objective of energy policy is to promote ‘green growth’, i.e. the use of renewable electricity which does not generate CO2 emissions. On the surface, these policies may look complementary (as argued in Kemfert and Deikmann, 2009; Kemfert et al. 2009) but it can also be argued that they may come into conflict (as argued in Böhringer et al., 2009). To understand the exact nature and extent of the interactions between these policies, however, requires a detailed examination of the structure of the electricity generation market with detailed descriptions of the type of technologies which are used for electricity generation. Unfortunately, this is not often forthcoming in most top-down computable general equilibrium used for the analysis of these policies. For example, in GTAP-E (Burniaux and Truong, 2002) as well as in most other top-down CGE models, the electricity supply sector is often represented simply by an aggregate production function which may use different (fossil) fuels as inputs but this masks rather than highlights the fact that these different fuels are in fact fuels used by different *technologies* and the substitution between these technologies is the main reason behind the fuel substitution rather than the reverse. Since some of the technologies do not even use any of these (fossil) fuels, for example hydroelectric, nuclear, and other renewable energy technologies, the ‘fuel-substitution’ representation is at best an inadequate description of the real substitution between the technologies. In an attempt to correct for this deficiency, other approaches have been used to describe the substitution between technologies, for example, the ‘technology bundle’ approach using an aggregate CRESH production function have been applied in some CGE models (ABARE, 1996; Pant, 2007), the ‘logit’ (multinomial logistic function) is also used to explain technology choice in other models (Schumacher and Sands, 2006). These approaches have the improvements of a detailed descriptions of the technologies from a ‘bottom-up’ perspective, however, they still rely mostly on the ‘top-down’ (aggregate production function) approach to explain the interactions between these technologies. This can lead to some inaccuracies in some areas. For example, in the case of the CRESH technology bundle approach, the summation of all the electricity outputs from all the technologies will not be equal exactly to the output of the electricity sector, and hence some ‘adjustment factor’ must always be used which is not directly explainable by the function itself.[[1]](#footnote-1) In the case of the logit approach, a discrepancy can occur between the summation of all the costs of the technologies and the total cost of the sector which is also not explainable by the approach itself.

In this paper, we provide an alternative to the aggregate production function approach in explaining the competition between the different technologies in the electricity market. We assume that different suppliers (players) in the market who use these different technologies face with different cost structures and hence have to rely on different strategies in protecting their cost base to maximize their profits. Those suppliers with technologies which exhibit constant returns to scale (CRTS) with flexible capital base (e.g. non-hydro renewable technologies) can recover their costs and maximize their profits simply by producing up to the level where the market price is equal to their marginal production costs (including marginal capital costs). That is, they can be perfect competitors or price takers in the market. On the other hand, other suppliers with technologies which can exhibit some degree of scale economies due to the problem of indivisibility of capital (i.e. large up-front capital costs) such as coal, nuclear or hydro electricity technologies may not be able to produce up to the level where the market price is equal to their marginal production costs and still recover all costs (because of this large up-front capital costs). In these cases, suppliers face with a decreasing average cost curve and hence cannot increase production to reduce cost if in so doing they also reduce the market price and therefore reduce their profit. Profit maximizing behaviour in this case requires the suppliers to act as though a ‘natural monopolist’ (Baumol, 1977), or as a Cournot oligopolist (if there are more than one players using technologies of this type) who require a mark-up of market price over marginal costs to recover all costs (or to maximize profits). Competition between these Cournot oligopolists on the one hand, and between the oligopolists with the ‘fringe competitors’ on the other hand is the main driving force behind the competition between the technologies. The equilibrium outcome for the electricity supply market therefore is best described in terms of this model of ‘dominant versus fringe’ imperfect competition rather than as a case of perfect competition between all suppliers who use CRTS technologies (as is implicitly assumed in all aggregate production function approach).

The plan of the paper is as follows. Section 2 presents a theoretical analysis of the electricity supply market and provides a model to describe the behaviour of different players in this market. Section 3 applies this model to an empirical example, using the case of Japan electricity market as an illustration. Section 4 reviews the results and give some conclusion.

1. **Theoretical analysis of the electricity supply sector**

Electricity has some special characteristics which makes the analysis of the electricity market rather challenging. First, electricity is a non-storable commodity[[2]](#footnote-2) therefore this imposes a special restriction on production activity: *output* at any time cannot exceed *capacity* for production, and capacity is not easily divisible (i.e. continuously variable) and expensive to install. Secondly, electricity demand is highly fluctuating in the short run as well as in the long run, but particularly in the short run where the issue of capacity planning must be considered so that supply can meet with the level of demand at any time. Traditionally, the issue of capacity planning is often considered under the assumption that total demand can be classified into various types of ‘loads’ (e.g. peak load, intermediate load, and base load) each can be met with a different type of capacity. Base load demand which exists in all periods of time will have to be met with a type of capacity which is available throughout most of the time, while intermediate and peak load demand which exist only during some intermediate or peak periods can be satisfied with capacities which can be turned on for these periods only. Base load capacity typically will have the lowest marginal running cost even if marginal capital (i.e capacity) cost can be high.[[3]](#footnote-3) In contrast, peak load capacity will have high marginal running cost while marginal capital cost can be lower, and intermediate load capacity is somewhere in between the peak and base load capacity in cost characteristics. Often base load capacity is provided by coal and nuclear energy based technologies, while peak load capacity is provided by oil and gas based electricity technology. Renewable electricity technology in principle can be used to provide for all of these types of capacity but in practice this depends on the availability factor[[4]](#footnote-4) which in turn is determined primarily by seasonal and weather conditions rather than by cost factors alone. As a result, it can be assumed that ‘price elasticity of supply’ for renewable electricity is to be determined in practice by geographical information system (GIS) rather than by just economic factors (such as capital and labour running costs), in contrast to non-renewable electricity where the economic factors are the more important factors.

In Figure 1, we show the electricity market as consisting of an average demand curve *Dave* (averaged over a particular period of time such as a year of 8760 hours), and a ‘capacity supply curve’ which consists of a base load capacity, intermediate load capacity and peak load capacity respectively adding up to the total capacity which is available for the production of electricity throughout the year. The cost characteristics of these capacities are shown as *C*1, *C*2, and *C*3 respectively which represent the (constant) marginal cost[[5]](#footnote-5) of producing electricity using these capacities. The base load capacity is seen to have the lowest marginal cost of *C*1. Next comes the intermediate capacity with intermediate level marginal cost *C*2, and finally, peak load capacity with the highest marginal cost *C*3. Assuming that the (yearly) demand for electricity can be ‘ordered’ in such a way that the hourly demand for electricity can go from the lowest level (on the left) to the highest level (on the right) – as represented by the three different ‘demand curves’ *D*1, *D*2, *D*3 in Figure 1- when demand is lowest at *D*1 , only base load capacity is utilized, with a marginal cost of supply of *C*1 whereas if demand is highest at *D*3 all types of capacities must be used, with the highest marginal cost of supply of *C*3. On average it can be said that demand is at the level *D*aveas shown on the right hand graph of Figure 1, and the average *cost* of supply is *C*ave To determine the actual supply *curve* for electricity, however, this is more involved. It is because this depends on the structure of the market and on assumptions made about supply behaviour of different players in the market especially if they are using different technologies with substantially different cost structures. For example, if it can be assumed that all suppliers are using technologies which exhibit CRTS[[6]](#footnote-6) and hence having a LRMC curve which is either horizontal or upward sloping, and if all suppliers are price takers (as in a perfectly competitive market situation), then the *aggregate* supply curve for the market as a whole can be assumed to be the horizontal summation of all the LRMC curves. However, if some suppliers are using technologies which may exhibit some degree of ‘scale economies’, for example, those which involve large up-front (i.e. fixed) capital costs but with low marginal running costs, then the existence of scale economies in their production level can imply some degree of ‘natural monopolistic’ power (see Baumol, 1977). This power can allow the suppliers to influence the level of supply price and not acting simply as price takers as assumed in traditional perfectly competitive model. In this case, the ‘supply curve’ for these market players will not be well-defined. Instead, the strategic interactions between these players is the main reason behind the market outcome. In this paper, following the approach often adopted in most studies on the electricity supply market, we make a distinction between the supply behaviour of those who use CRTS technologies (assumed[[7]](#footnote-7) to include oil, gas, and renewable energy based technologies) and those who use technologies which can exhibit some degree o scale economies (assumed to include coal, hydro, as well as nuclear energy based electricity generation technologies). It is assumed that the former group of suppliers will behave as perfect competitor or price-takers, while the latter group may[[8]](#footnote-8) behave as though Cournot oligopolists[[9]](#footnote-9)

Let *qi* be the output of an individual *i*-producer in the *L*-group (‘*L*’ stands for market leaders) and *qj* be the output of an individual *j*-producer in the *F*-group (‘*F*’ stands for market followers or fringe competitors). If *Q* is the total supply level for the market, then production constraint for the market implies:

 (1)

Assuming that fringe competitors are all CRTS producers with a price elasticity of supply equal to . The aggregate supply curve for the *F-*group as a whole can then be said to have an (aggregate) price elasticity of supply equal to:

 (2)

where *sj* = (*qj*/*QF*) is the relative market share of the *j*-producer within the *F*-group.

Given the aggregate supply curve for the *F*-group, and given the total market demand curve for electricity as a whole being given as *P*=*P*(*Q*), a ‘residual’ market demand curve for the *L-*group can then be derived as follows:

 (3)

Here, is the aggregate price-elasticity of demand for electricity as a whole, as determined by the aggregate market demand curve, *SL* = (*QL*/*Q*), *SF* = (*QF*/*Q*) are the relative market shares of the *L*-group and *F*-group respectively, and is the price-elasticity of demand for electricity supplied by the *L*-group.  therefore determines the ‘shape’ of the residual demand curve for electricity supplied by the *L*-group, and producers from the *L*-group will take this ‘residual’ demand curve as their own in their strategic interactions with each other to maximize their individual profits. To describe this strategic interactions in more details, assume that each producer from the *L*-group acts as a Cournot oligopolistic competitor, i.e. each will try to maximize their own individual profit taking the ‘residual’ market demand curve as given and also assuming the production levels of all other Cournot competitors as given, i.e.:

 (4)

Here, is the profit function of the individual *i*-producer from the *L*-group taking the level of production of all other members in the group. i.e. as given, is the inverse of the residual demand function for the *L*-group, and is the total cost function for the *i*-producer. Assuming that both and are differentiable functions, then the first-order condition for an optimal solution to the problem (4) is:

 (5)

where (*’*)denotes the first derivative of the corresponding function. In this equation, the first two terms on the left-hand side of the equation represent the marginal revenue from an additional unit of output, while the third term represents the (short run)[[10]](#footnote-10) marginal cost of that output. Thus, the first-order condition for profit maximization requires that marginal revenue equal marginal cost. In maximizing its own profits, each supplier assumes that the output of all other oligopolistic competitors are given therefore *dqi=dQL*, Referring back to the equation but now dropping the arguments of each function for notational simplicity, the equation can be rewritten as:

 (6)

or

 (7)

where *MCi***represents the short run marginal cost for firm *i*, represents the price elasticity of demand of the residual demand curve (for the *L*-group only) and *si* = (*qi*/*QL*) is the relative market share of the *i*-supplier within the *L*-group.

Now consider the situation when the marginal cost for the supplier changes. Let *i* be the ratio of change in the marginal cost for supplier *i*, so that *iMCi* is the new marginal cost level for firm *i* and let ** be the ratio of change in the equilibrium price for the *L-*group after the marginal cost changes so that *PL* is the new equilibrium price for the *L*-group as a result of the marginal cost changes. Solving for ** using the last equation (7) yields

 (8a)

 (8b)

where and  are the relative share for supplier *i* before and after the marginal cost changes respectively. Summing over all *i*’s and noting that , we have

 (9)

or:

 (10)

In the special case when is the same for all *i*’s, then **is also equal to *.* In general, however, can be different for different *i’s*, therefore, the ratio of change in the price level will be given by the weighted sum of the changes in the marginal costs over the sum of the old marginal costs.

Note that equation (10) can also be written in an equivalent ‘percentage change’ form:

 (11)

where is the percentage (or rate of) change[[11]](#footnote-11) in the price level  and is the percentage (or rate of) change in the marginal cost level . Equation (11) therefore states that rate of change in the price level will be given by the weighted sum of the rates of changes of the marginal costs divided by the sum of the old marginal costs. Equation (10) or (11) can be used to determine the impact of the (rate of) changes in the marginal costs of supplier(s) *i’s* (for example, following the imposition of a carbon tax, or an emission trading scheme in the electricity sector) on the equilibrium supplier price in the electricity market, assuming that the impacts of these policies are mainly on the marginal costs of the *L-*group suppliers rather than on the fringe suppliers.[[12]](#footnote-12)

Price/Costs
($/kWh)

Costs
($/kW)

*D*ave

*D*3

*D*2

*C*3

*P*ave = *C*ave

*C*2

*D*1

*C*1

*Q*

Production
(MWh)

Capacity
(MW)

Peak

Intermediate

Base

Figure 1
Capacity and production level in the electricity generation market

Costs

*L*

*PM*

*PC*

*QL+QF =Q*

*C*

DR

Quantity
of electricity

*PL*

Electricity market

Fringe competitors using CRTS technologies

Leading suppliers using technologies which display some degree of scale economies due to large upfront fixed costs

D*ave*

*P*

(a)

(b)

(c)

*P*

LRMCC

MR

*M*

*QL*

Costs

SRMCL

SRATCL

*QF*

Price

Cournot oligopolists’ profit

Monopoly profit

*QM*

*QC*

Figure 2

Strategic behaviour between (a) Cournot oligopolists price leaders (*L*) using technologies which have scale *e*conomies, and (b) perfectly competitive fringe suppliers (*F*) who use technologies which have no scale economies, in (c) the electricity market (graphs are not to scale).

1. **Application to the case of Japan**

Electricity in Japan is produced from coal, oil, gas, nuclear energy and hydro power[[13]](#footnote-13) with some small proportions from renewable energy sources. To decompose the electricity sector in the GTAP v8 data base (Narayanan and Walmsley, 2008) into these different technologies, we use a methodology which can be described as follows. First we define the set of electricity generation technologies as consisting of those using coal, oil, gas, nuclear energy, hydro power, onshore wind, solar energy, biomass, waste, and other renewable energy (mainly geothermal). To facilitate a study into future usage of carbon capture and storage (CCS) technologies, we also add coal CCS, oil CCS, and gas CCS to the set of technologies by taking away 1% of the shares from coal, oil, and gas respectively and giving these to the CCS counterpart. Next to distribute the values of the inputs into the electricity sector in the GTAP data base to these technologies, we make the following assumptions.

1. *Fuel inputs*: all coal inputs are to go into the coal and coal CCS technologies (in the proportion 1/1.2 (i.e. assuming CCS technologies use 20% more fuels than non-CCS counterpart)[[14]](#footnote-14); similarly for gas: into gas and gas CCS technologies, oil into oil and oil CCS technologies. The distribution of ‘p\_c’ input requires some consideration: GTAP v8 data base describe ‘p\_c’ as “petroleum & coke: coke oven products, refined petroleum products, processing of nuclear fuel”, this means part of the p\_c input should go into the nuclear technology. To determine how much of this is fuel input into the nuclear technology, the p\_c input is first distributed to the ‘oil’ technology, so that, together with oil input, this makes up about 51% of the value of the oil technology output.[[15]](#footnote-15) The rest then go into the nuclear technology. This makes up about 8.9% of the value of the nuclear technology output. The ratio of fuel to output value for the nuclear technology in Japan in 2007, however, is estimated to be about 21% which is much greater than 8.9%, therefore, some other fuel must go into the nuclear technology to make up for this total. In theory, uranium must be the main source of fuel input into the nuclear technology, but in the GTAP data base, there is no explicit ‘uranium’ commodity. The ‘mining’ and ‘minerals’ commodities which would have included ‘uranium’ have a negligible value relative to the value of electricity output of the nuclear technology hence this cannot be sufficient to account for the main fuel input into the nuclear technology. Instead, therefore, in addition to the p\_c input, we use part of the electricity input into electricity sector as a whole to represent some of the fuel input into the nuclear technology, to make up to the total value of 21%. The rest of the electricity input can then be distributed to all other technologies in accordance with the value of their outputs.
2. *Capital inputs*: we use the EIA (2013) information on ‘overnight capital cost’ ($/kW) – see Table 1, and also information on installed capacities (Million kW) for electricity generation by various technologies in Japan[[16]](#footnote-16) to estimate the values of the capital *stock* ($ million) of these technologies. The ‘capital’ value input in the GTAP database, however, refers to capital *services* rather than capital stock, hence, we use the proportion of capital stock in various technologies (as estimated from the EIA capital stock values) only to distribute the total value of GTAP capital service input into the electricity sector to various technologies (assuming that these service flows are proportional to the value of the capital stock).
3. *Labour inputs*: the EIA (2013) information on fixed ($/kW-yr) and variable ($/MWh) O&M (operation and maintenance) costs– see Table 1, together with the information on production outputs (billion kWh) of various technologies can be used to estimate the total value of O&M costs for each technology. Assuming that these costs consist mainly of labour (and some material costs) the relative proportions of these costs in various technologies can then be used to distribute the total GTAP value of labour inputs into the electricity sector to these various technologies.
4. *Intermediate material inputs*: these material inputs can be said to be associated with activities (such as transmission and distribution of electricity) which are not technology specific, as well as with the generation activities which are technology specific. However, we can assume that all these inputs belong to the various technologies in proportion to the values of their outputs hence the distribution of total value of the GTAP intermediate material inputs into the various technologies are also in proportion to these output values.
5. *Relative costs or supply prices:* the aggregation of all the values of intermediate inputs, fuel inputs, capital and labour inputs into the various technologies make up the ‘supply price’ for each technology. These are shown in Table 2, together with the output quantities of each technology.

Having decomposed the electricity sector data for Japan into various technologies,[[17]](#footnote-17) the next step is to modify an existing CGE model[[18]](#footnote-18) to allow the supply of electricity in the model to be represented by combination of different suppliers (‘players’) using different types of technologies rather than by a single supplier using a single aggregate. The modification of the CGE model follows the theoretical description in the previous section. First, we define the set of ‘competitive fringe suppliers’ with technologies which exhibit CRTS in production. In the case when the market is assumed to be perfectly competitive, all suppliers are ‘fringe competitors’. The price elasticities of supply for all the technologies may be different due to their different cost structures as well as different availability of natural resources used in these technologies.[[19]](#footnote-19) For the illustrative experiment considered in this paper, we assume for simplicity that price elasticity of supply is equal to 2 for fossil fuel technologies, 2.7 for non-hydro renewable technologies (see, for example, Johnson, 2010), 0 for nuclear (to reflect the assumption that nuclear technology is to be phased out), and 1 for hydro technology. Price elasticity of demand for the electricity market is assumed to be 0.2 (see Epsey and Epsey, 2004; Wade, 2005). In the case when some suppliers are assumed to be using technologies which exhibit scale economies, and hence cannot behave as perfectly competitive price-takers but act as Cournot oligopolists, a residual demand curve must be estimated. The price elasticity for this residual demand curve is given Table 3 where it is seen that as the number of oligopolists increases (or the number of fringe competitors decrease), the price elasticity of the residual demand curve will decrease as expected.

Following a ‘shock’ to the cost structures of some or all of the technologies, the supply curves of the ‘fringe competitors’ may shift (which will affect the residual demand curve) and also the cost curves of the Cournot oligopolists may also shift. This implies a new equilibrium must be established and this is defined by equation (10) or (11)).

In order to compare the results of the model with the results of other conventional CGE models which use the CRESH ‘technology bundle’ approach, the model is also built with an option to estimate the results of this approach. For the CRESH technology bundle approach, the supply behaviour of the different technologies is described by the following equation:

 (12)

where (*qi*) is the percentage change in quantity of technology *i* and (*pi*) is the percentage change in its price; () is the modified value share of input *i* which is related to the ordinary value share () via the relationship: (see Dixon *et al.* (1982), p. 86 for more details); () are the CRESH elasticities of substitution which are related to the own- and cross-price elasticities of demand for the technologies as follows:[[20]](#footnote-20)

 (13)

 (14)

Note that if there are *n* CRESH elasticities, there are *2n* parameters (*n*and *n*) to be determined from equation (13) and (14) using the (2*n*!-*n*)values of the price elasticities. If the cross-price elasticities can be scaled by the value shares to be symmetric[[21]](#footnote-21) then there are (*n*!)own and cross-price elasticities to be used to determine the values of the *2n* parameters mentioned. In the special case when *n*=3, the number of parameters to be determined therefore equal exactly the number of the (calibrated) price elasticities. We can use this special case to find the CRESH parameters for fossil fuel technologies (Coatec, Oiltec, Gastec), using the values of the own and cross price elasticities of these technologies (as given in Table 4)[[22]](#footnote-22) and calibrated with the GTAP value shares. Once the demand for these (aggregate) technologies are known, they can then be disaggregated into the conventional and CCS counterpart, for example, Coatec into ElyCoa and CoaCCS, etc.[[23]](#footnote-23) For the case of non-fossil fuel technologies, we assume the CRESH parameters are equal to price elasticity of *supply[[24]](#footnote-24)* for the technology. Thus for example, the value of () for nuclear electricity is assumed to be equal to zero (to reflect Japanese policy restriction on nuclear electricity expansion) while that for non-hydro renewable technologies is assumed to be equal to 2.7 (which are the values as estimated for the US in Johnson (2014)). The price elasticity of supply for hydro electricity can be assumed to be equal to 1 (i.e. much less than 2.7 but greater than 0) to reflect the more severe resource constraint on hydro electricity development as compared to other renewable technologies. Given these assumptions, the own-price and cross-price elasticities of demand for the technologies can be estimated using the GTAP value shares and they are given in Table 5.

***Example: Japan’s Kyoto Protocol climate policy without an accompanying energy policy***

Japan’s obligation under the Kyoto Protocol involves cutting back on CO2 emissions (from the level of 2007) by about -31.8%. Without any emission trading with any other countries, this would involve Japan imposing either a carbon tax, or an emissions trading scheme on the domestic economy. The level of carbon tax (or emission permit price) required to achieve this target level of reduction in CO2 emissions is given in Table 6 under different assumptions about the structure of the electricity generation market. If the market is assumed to be perfectly competitive (PC) and substitution between the technologies can be assumed to be described by a CRESH production function, then the results are as shown in the column “CRESH” of Table 6.[[25]](#footnote-25) On the other hand, if the market is assumed to lack the characteristics of a PC market, with some suppliers (especially those using coal, nuclear, or hydro electricity technologies) exhibit the characteristic of a Cournot monopolist or oligopolist when setting their production levels, then the results are as shown in column “IC” (for imperfect competition) of Table 6. Here we can look at three different cases when (i) only one supplier (using coal technology) is assumed to behave as an imperfect competitor, when (ii) two suppliers (those using coal as well as nuclear technology) are assumed to behave as imperfect competitors, and when (iii)three suppliers (those using coal, nuclear, as well as hydroelectricity technology) are assumed to behave as imperfect competitors,

Table 7 shows the changes in production levels for different sectors and technologies technologies in the Japanese economy following the imposition of the climate change policy outcome under these different assumptions about market structure. Table 8 shows corresponding changes in price level. Table 9 shows the results in terms of market shares for different technologies following from the imposition of the climate change policy with no accompanying energy policy. The results are also illustrated in Figure 3a, b.

Overall the results show that the market outcomes as well as outcomes for individual technologies are quite different depending on different assumptions made about market structure, as can be expected. Comparing the technology bundle approach using CRESH aggregate production function to represent the electricity market, and the imperfect competition approach suggested in this paper, it can be seen that (i) the CRESH results are quite sensitive to the output adjustment which is (arbitrarily) made to ensure all outputs of technologies sum to the total sectoral output, in once case (Elygas technology) the adjustment may even lead to negative market share which is an infeasible result, (ii) CRESH results may give more emphasis to Nuclear and Hydro technology competition with respect to coal technology (even with some restriction on supply elasticities (i.e. on CRESH substitution parameters) while IC results play down this competition because both Nuclear and Hydro technologies have cost structures which are similar to coal technologies (i.e. large upfront capital costs and hence economies of scale in production). This restricts their abilities to compete with coal because their average unit costs are more a function of production level rather than marginal costs hence even if the marginal costs for Elycoa may increase (because of climate policy) this may not be sufficient to drive the three (potentially Cournot) oilgopolists to become price competitors instead of quantity competitors.

In general, neither the CRESH approach nor our IC approach can suggest that climate change policy alone would be sufficient to change significantly the share of technologies in electricity generation mix. This will require some accompanying energy policy policy, and this will be a topic for study in a future study.

1. **Conclusion**

In this paper we have shown a new way for disaggregating the electricity sector in a CGE model to take account of different technologies used in the sector. Compared to (top-down) approaches which still rely on aggregate production function to illustrate the (imperfect) competition between the technologies – by using the assumption of perfect competition between imperfect substitutes, we have adopted a different assumption: imperfect competition between perfect substitutes. The results of our illustrative simulation shows that the two different sets of assumptions can lead to quite different results, hence future studies may need to look more carefully at the issue of market structure in the electricity market to find solution to the market equilibrium issue rather than relying merely on a comparison between different cost *levels* to arrive at conclusions about the dynamic outcome in this market.

Table 1: U.S. Cost Characteristics of Electricity Generating Technologies

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Technology** | **EIA Specification** | **Overnight Capital Cost****($/kW)** | **Fixed O&MCost****($/kW-yr)** | **Variable O&M Cost****($/MWh)** |
| **Coal** | Scrubbed Coal New  | 2,925  | 31  | 4 |
| **Oil** | Conv. Gas/Oil Comb Cycle | 915  | 13  | 4 |
| **Gas** | Advanced Gas/Oil CC  | 1,021  | 15  | 3 |
| **Nuclear** | Adv Nuclear  | 5,501  | 93  | 2 |
| **Hydro** | Conventional Hydroelectric  | 2,435  | 15  | 3 |
| **Wind** | Onshore Wind  | 2,213  | 40  | 0 |
| **Solar** | Photovoltaic  | 3,564  | 25  | 0 |
| **Biomass** | Biomass CC | 4,114  | 106  | 5 |
| **Waste** | Municipal Solid Waste | 8,312  | 393  | 9 |
| **Other Renewables** | Geothermal | 2,494  | 113  | 0 |
| **Coal CCS** | Dual Unit Advanced PC with CCS | 6,567  | 73  | 8 |
| **Oil CCS** | Advanced CC with CCS | 2,084  | 32  | 7 |
| **Gas CCS** | Advanced CC with CCS | 2,084  | 32  | 7 |

Source: EIA (2013a), Arora and Cai (2014).

Table 2: Electricity Generating Technologies in Japan in 2007

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Technology** | **Output sharein 2007** | **Output****(Billion kWh)** | **Capacity(Million kW)** | **Capital input($million)** | **Labour input($million)** | **Fuel input($million)** | **Non-fuel inputs****($million)** | **Supply price****($/kWh)** |
| **Coal** | 0.285 | 307.5 | 43.87 | 8628.8 | 3227.6 | 6423.4 | 12024.6 | 0.099 |
| **Oil** | 0.115 | 124.0 | 78.61 | 4836.7 | 946.6 | 25865.2 | 4847.9 | 0.294 |
| **Gas** | 0.257 | 276.9 | 54.50 | 3741.8 | 1817.1 | 15351.3 | 10830.3 | 0.115 |
| **Nuclear** | 0.248 | 267.3 | 47.47 | 17560.7 | 4696.8 | 4597.6 | 10455.7 | 0.140 |
| **Hydro** | 0.064 | 68.6 | 47.31 | 6197.5 | 450.3 | 0.0 | 2683.8 | 0.136 |
| **Wind** | 0.002 | 2.6 | 1.53 | 181.8 | 16.7 | 0.0 | 102.6 | 0.115 |
| **Solar** | 0.002 | 2.0 | 1.92 | 367.9 | 8.0 | 0.0 | 78.8 | 0.226 |
| **Biomass** | 0.016 | 16.8 | 2.13 | 588.3 | 399.2 | 0.0 | 655.7 | 0.098 |
| **Waste** | 0.006 | 6.2 | 0.79 | 441.8 | 467.5 | 0.0 | 243.8 | 0.185 |
| **Other Renewables** | 0.003 | 3.0 | 0.53 | 71.4 | 54.7 | 0.0 | 119.0 | 0.081 |
| **Coal CCS** | 0.001 | 1.1 | 0.18 | 77.6 | 24.5 | 27.0 | 42.2 | 0.159 |
| **Oil CCS** | 0.001 | 1.1 | 1.23 | 172.5 | 16.0 | 324.0 | 42.2 | 0.514 |
| **Gas CCS** | 0.001 | 1.1 | 0.25 | 34.5 | 16.0 | 71.7 | 42.2 | 0.152 |
| **Total** | 1 | 1078.2 | 280.32 | 8628.8 | 3227.6 | 54334.0 | 42168.8 | 0.141 |

Table 3: Price elasticity of demand for the residual demand curve when some suppliers are olo\igopolists

|  |  |
| --- | --- |
| **Oligopolist price leader(s)** |  |
| **ElyCoa** | -3.82 |
| **ElyCoa, ElyNu** | -2.04 |
| **ElyCoa, ElyNu, ElyHyd** | -1.72 |

Table 4: Price elasticities of demand for fossil fuel technologies used for calibrating CRESH substitution parameters

|  |  |  |  |
| --- | --- | --- | --- |
| **Technology** | **Coaltec** | **Coaltec** | **Coaltec** |
| **Coaltec** | -0.46 | .07 | .10 |
| **Oiltec** | .07 | -.48 | .32 |
| **Gastec** | .10 | .32 | -1.12 |

Table 5:Technology parameters

|  |  |  |
| --- | --- | --- |
| **Technology** | CRESH parameter() | **Own and cross price elasticities****(**) |
| **Coaltec** | **Oiltec** | **Gastec** | **Nuclear** | **Hydro** | **Wind** | **Solar** | **Biomass** | **Waste** | **Other Renewables** |
| **Coaltec** | 0.70 | -0.60 | 0.10 | 0.38 | 0 | 0.06 | 0.00 | 0.01 | 0.02 | 0.02 | 0.00 |
| **Oiltec** | 0.56 | 0.09 | -0.47 | 0.30 | 0 | 0.04 | 0.00 | 0.01 | 0.02 | 0.01 | 0.00 |
| **Gastec** | 2.32 | 0.37 | 0.34 | -1.07 | 0 | 0.18 | 0.02 | 0.02 | 0.08 | 0.05 | 0.01 |
| **Nuclear** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Hydro** | 1.00 | 0.16 | 0.15 | 0.54 | 0 | -0.92 | 0.01 | 0.01 | 0.03 | 0.02 | 0.01 |
| **Wind** | 2.70 | 0.42 | 0.40 | 1.46 | 0 | 0.21 | -2.68 | 0.03 | 0.09 | 0.06 | 0.01 |
| **Solar** | 2.70 | 0.42 | 0.40 | 1.46 | 0 | 0.21 | 0.02 | -2.67 | 0.09 | 0.06 | 0.01 |
| **Biomass** | 2.70 | 0.42 | 0.40 | 1.46 | 0 | 0.21 | 0.02 | 0.03 | -2.61 | 0.06 | 0.01 |
| **Waste** | 2.70 | 0.42 | 0.40 | 1.46 | 0 | 0.21 | 0.02 | 0.03 | 0.09 | -2.64 | 0.01 |
| **Other Renewables** | 2.70 | 0.42 | 0.40 | 1.46 | 0 | 0.21 | 0.02 | 0.03 | 0.09 | 0.06 | -2.69 |

Table 6: Kyoto Protocol Scenario results.

|  |  |  |  |
| --- | --- | --- | --- |
| No. | Region | % CO2 emissions reduction under Kyoto Protocol | Carbon price (2007 $US/tCO2) under different electricity market structure assumptions |
| CRESH (a)with output adjustment | CRESH (b)without output adjustment | IC (1)ElyCoaas IC | IC (2)ElyCoa, ElyLWRas ICs | IC (3)ElyCoa, ElyLWR ElyHydas ICs |
| 1 | CHN |  | 0 | 0 | 0 | 0 | 0 |
| 2 | IND |  | 0 | 0 | 0 | 0 | 0 |
| 3 | JPN | -31.8 | 167 | 76.5 | 182.4 | 199.2 | 199 |
| 4 | KOR |  | 0 | 0 | 0 | 0 | 0 |
| 5 | ASIA |  | 0 | 0 | 0 | 0 | 0 |
| 6 | USA | -35.6 | 135 | 134.5 | 135.6 | 135.6 | 135.6 |
| 7 | CAN | -35.7 | 131.9 | 131.6 | 132.3 | 132.3 | 132.3 |
| 8 | AUS | -35.7 | 129.5 | 129.2 | 130.3 | 130.2 | 130.2 |
| 9 | EU12 | -22.4 | 118.1 | 117.1 | 119 | 119.1 | 119.1 |
| 10 | DEU | -22.4 | 107.3 | 106.4 | 108.2 | 108.3 | 108.3 |
| 11 | FRA | -22.4 | 132.7 | 131.6 | 133.8 | 134 | 133.9 |
| 12 | GBR | -22.4 | 96 | 95.3 | 96.6 | 96.7 | 96.7 |
| 13 | RUS |  | 0 | 0 | 0 | 0 | 0 |
| 14 | CEU |  | 0 | 0 | 0 | 0 | 0 |
| 15 | RoA1 | -35.7 | 215 | 214.3 | 215.6 | 215.7 | 215.7 |
| 16 | LSA |  | 0 | 0 | 0 | 0 | 0 |
| 17 | RoW |  | 0 | 0 | 0 | 0 | 0 |

Table 7: Change in production level.

|  |  |  |
| --- | --- | --- |
| No. | Sector/technology | % Change in production level following climate change policy .under different assumptions regarding electricity market structure |
| CRESH (a)with output adjustment | CRESH (b)without output adjustment | IC (1)ElyCoaas IC | IC (2)ElyCoa, ElyLWRas ICs | IC (3)ElyCoa, ElyLWR ElyHydas ICs |
| 1 | agr | -1.1 | -0.3 | -0.7 | -0.8 | -0.9 |
| 2 | coa | -17.5 | -13.1 | -24.6 | -24.9 | -24.6 |
| 3 | oil | -18 | -14.4 | -17.2 | -18 | -18.1 |
| 4 | gas | -31.1 | -22.2 | -20.5 | -23.7 | -24.3 |
| 5 | p\_c | -13.9 | -5.3 | -17.2 | -18.5 | -18.4 |
| 6 | ely | 36.2 | 19 | -9.9 | -4.8 | -2.8 |
| 7 | i\_s | -4.5 | -2 | -11.7 | -11.6 | -11.3 |
| 8 | nfm | 1.8 | 0.9 | -6.8 | -5.9 | -5.5 |
| 9 | min | -2.1 | -0.8 | -4.1 | -4.1 | -4 |
| 10 | crp | -4 | -1.2 | -6.6 | -6.9 | -6.8 |
| 11 | omf | -1.3 | -1 | -2.1 | -2.1 | -2 |
| 12 | trp | -2.5 | -0.4 | -3.2 | -3.5 | -3.5 |
| 13 | ser | -0.5 | -0.1 | -0.4 | -0.5 | -0.5 |
| 14 | CGDS | -0.16 | -0.01 | 0.05 | 0.03 | 0.02 |
|  | ElyCoa | -12.2 | -52.4 | -91.3 | -39.5 | -25.7 |
|  | ElyOil | 106.8 | 15.6 | 47.9 | 30.8 | 24.5 |
|  | ElyGas | -81.8 | -69.1 | 47.9 | 30.8 | 24.5 |
|  | ElyLWR | 163.5 | 19.0 | 0 | -39.5 | -25.7 |
|  | ElyHyd | 157 | 16.4 | 21.6 | 14.4 | -25.7 |
|  | ElyWON | 146.4 | 12.2 | 69.5 | 43.7 | 34.4 |
|  | ElySol | 146.4 | 11.9 | 69.5 | 43.7 | 34.4 |
|  | ElyBio | 146.8 | 12.6 | 69.5 | 43.7 | 34.4 |
|  | ElyWas | 147.1 | 12.4 | 69.5 | 43.7 | 34.4 |
|  | ElyOth | 146.8 | 12.7 | 69.5 | 43.7 | 34.4 |
|  | CoaCCS | 55.5 | -22.9 | 47.9 | 30.8 | 24.5 |
|  | OilCCS | 218 | 47.4 | 47.9 | 30.8 | 24.5 |
|  | GasCCS | -57.8 | -45.1 | 47.9 | 30.8 | 24.5 |

Table 8: Change in price level.

|  |  |  |
| --- | --- | --- |
| No. | Sector/technology | % Change in price level following climate change policy .under different assumptions regarding electricity market structure |
| CRESH (a)with output adjustment | CRESH (b)without output adjustment | IC (1)ElyCoaas IC | IC (2)ElyCoa, ElyLWRas ICs | IC (3)ElyCoa, ElyLWR ElyHydas ICs |
| 1 | agr | 2.4 | 1.9 | 2.0 | 2.1 | 2.1 |
| 2 | coa | -4.8 | -3.3 | -7.7 | -7.7 | -7.6 |
| 3 | oil | -5.4 | -4.0 | -6.5 | -6.7 | -6.7 |
| 4 | gas | 3.3 | 2.4 | 1.7 | 2.0 | 2.1 |
| 5 | p\_c | -1.3 | -3.0 | -0.2 | 0.0 | 0.0 |
| 6 | ely | -26.2 | -16.0 | 21.6 | 14.4 | 11.6 |
| 7 | i\_s | 3.7 | 2.0 | 9.7 | 9.5 | 9.2 |
| 8 | nfm | 0.5 | 0.8 | 3.2 | 2.9 | 2.7 |
| 9 | min | 4.0 | 2.6 | 7.0 | 7.0 | 6.9 |
| 10 | crp | 2.6 | 1.4 | 3.9 | 4.1 | 4.0 |
| 11 | omf | 1.5 | 1.4 | 2.0 | 1.9 | 1.9 |
| 12 | trp | 7.2 | 3.9 | 7.6 | 8.2 | 8.2 |
| 13 | ser | 1.6 | 1.6 | 0.8 | 0.9 | 0.9 |
| 14 | CGDS | 1.6 | 1.6 | 1.2 | 1.2 | 1.3 |
|  | ElyCoa | 23.9 | 21.2 | 0.9 | 12.1 | 12.1 |
|  | ElyOil | 1.9 | -1.7 | 38.5 | 42.6 | 42.8 |
|  | ElyGas | 26.4 | 11.9 | 47.5 | 53.3 | 54.4 |
|  | ElyLWR | -29.7 | -17.6 | 2.5 | -30.2 | -29.3 |
|  | ElyHyd | -24.4 | -14.1 | -1.2 | -0.9 | -30.6 |
|  | ElyWON | -24.4 | -14.1 | -0.8 | -0.5 | -0.5 |
|  | ElySol | -24.4 | -14 | -1.6 | -1.4 | -1.3 |
|  | ElyBio | -24.4 | -14.2 | 0.2 | 0.4 | 0.4 |
|  | ElyWas | -24.4 | -14.2 | -0.2 | 0 | 0 |
|  | ElyOth | -24.4 | -14.2 | 0.4 | 0.5 | 0.5 |
|  | CoaCCS | 10.5 | 10.1 | 97.3 | 45.5 | 41.2 |
|  | OilCCS | -6.5 | -6.4 | 22.9 | 25.3 | 25.5 |
|  | GasCCS | 16.2 | 5.7 | 34.6 | 39 | 39.7 |

Table 9: Market shares for different technologies.

|  |  |  |
| --- | --- | --- |
| No. | Technology | Market share in base year and following imposition of climate change policy .under different assumptions regarding electricity market structure |
| Base year (2007) | CRESH (a)with output adjustment | CRESH (b)without output adjustment | IC (1)ElyCoaas IC | IC (2)ElyCoa, ElyLWRas ICs | IC (3)ElyCoa, ElyLWR ElyHydas ICs |
| 1 | ElyCoa | 0.285 | 0.147 | 0.082 | 0.053 | 0.186 | 0.220 |
| 2 | ElyOil | 0.115 | 0.196 | 0.111 | 0.181 | 0.156 | 0.146 |
| 3 | ElyGas | 0.257 | -0.046 | 0.031 | 0.405 | 0.348 | 0.327 |
| 4 | ElyLWR | 0.248 | 0.564 | 0.248 | 0.272 | 0.162 | 0.191 |
| 5 | ElyHyd | 0.064 | 0.141 | 0.062 | 0.084 | 0.076 | 0.049 |
| 6 | ElyWON | 0.002 | 0.005 | 0.002 | 0.004 | 0.004 | 0.003 |
| 7 | ElySol | 0.002 | 0.004 | 0.002 | 0.003 | 0.003 | 0.003 |
| 8 | ElyBio | 0.016 | 0.033 | 0.015 | 0.028 | 0.023 | 0.021 |
| 9 | ElyWas | 0.006 | 0.012 | 0.005 | 0.010 | 0.009 | 0.008 |
| 10 | ElyOth | 0.003 | 0.006 | 0.003 | 0.005 | 0.004 | 0.004 |
| 11 | CoaCCS | 0.001 | 0.001 | 0.001 | 0.002 | 0.001 | 0.001 |
| 12 | OilCCS | 0.001 | 0.003 | 0.001 | 0.002 | 0.001 | 0.001 |
| 13 | GasCCS | 0.001 | 0.000 | 0.000 | 0.002 | 0.001 | 0.001 |
|  | total | 1.000 | 1.065 | 0.562 | 1.052 | 0.974 | 0.976 |

Note: under CRESH (b) sum of shares does not equal 1, in other cases, the sums are not equal exactly to 1 due to rounding errors.



Figure 3a technology shares for all technologies



Figure 3b: technology share for non-hydro renewable technologies only

**Appendix**

Table A1: Details on regional aggregation.

|  |  |  |
| --- | --- | --- |
| No. | Region | Description |
| 1 | CHN |  China & Hong Kong |
| 2 | IND |  india |
| 3 | JPN |  Japan |
| 4 | KOR |  Korea |
| 5 | ASIA |  other Asian countries |
| 6 | USA |  United States |
| 7 | CAN |  Canada |
| 8 | AUS |  Australia |
| 9 | EU12 |  EU15 minus France, Germany, UK |
| 10 | DEU |  Germany |
| 11 | FRA |  France |
| 12 | GBR |  UK |
| 13 | RUS |  Russian Federation (Exclude Ukraine) |
| 14 | CEU |  Central & Eastern Europe  |
| 15 | RoA1 |  Other Annex 1 regions |
| 16 | LSA |  Mexico & Latin America |
| 17 | RoW |  Rest of the World |

Table A2: Details on sectoral aggregation.

|  |  |  |
| --- | --- | --- |
| No. | Sector | Description |
| 1 | agr | Agriculture forestry and fishing |
| 2 | coa | Coal mining |
| 3 | oil | Crude oil |
| 4 | gas | Natural gas extraction + Gas distribution |
| 5 | p\_c | Refined oil products |
| 6 | ely | Electricity |
| 7 | i\_s | Iron and Steel |
| 8 | nfm | Non-ferrous metal |
| 9 | min | Minerals nec + mineral products nec: supposed to include uranium mining |
| 10 | crp | Chemical, rubber, plastic products |
| 11 | omf | Manufactures nec and all other manufactures |
| 12 | trp | Transportation |
| 13 | ser | Services |

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1. See Arora and Cai (2014, p. 7). This inaccuracy can arise from the fact that electricity outputs from all technologies are in practice ‘perfectly substitutable’ (and hence can be simply added up), but the (technology bundle) approach assumes that they are imperfectly substitutable to avoid the problem of a corner solution. In practice some bottom-up models (using linear programming techniques) can avoid this problem of a corner solution by relying on the assumption of fixed capacity constraints for all technologies, but this is difficult to implement in an aggregate production function approach. [↑](#footnote-ref-1)
2. Even if storable, the cost of storing electricity is large hence it is impractical (and expensive) to consider storing electricity as a means to circumvent the production-capacity constraint issue. In this respect, electricity is similar to other ‘services’ (including transport as a service) even though electricity by nature is perhaps more like a ‘commodity’ rather than a service. [↑](#footnote-ref-2)
3. Which consists of a ‘short run marginal cost’ (SRMC) component representing the marginal operating and maintenance (i.e. running) cost and a ‘long run marginal cost’ (LRMC) component representing the marginal capital (or marginal capacity) cost. [↑](#footnote-ref-3)
4. Which is defined as the ratio of the total time during which electricity can be produced from a renewable electricity plant over the total time period being considered. [↑](#footnote-ref-4)
5. By ‘marginal cost’ it is here assumed to include both ‘short run’(operating and maintenance) marginal cost as well as long run (capacity or capital) marginal cost. [↑](#footnote-ref-5)
6. Constant returns to scale does not require that all production plants must have the same level of costs because quite clearly some plants are more efficient than others depending on their scale. However, it requires that the most efficient scale (also called minimum efficient scale (MES) for a plant) must be much smaller than the size of the market or the level of the demand for which the plant is to serve. This will allow the most efficient production level (and hence the lowest level of average production cost) to be achieved. It can be said that while renewable electricity as well as oil and gas based electricity generation plants can exhibit this property, this may not be the case with coal and nuclear energy based electricity generation plants. The MES for these latter technologies can be significantly large relative to the size of the market or the demand level for which the plants are to be built for. Therefore, at times, with a reduction in production level, the average total cost may increase substantially relative to the most efficient (i.e. minimum) cost. [↑](#footnote-ref-6)
7. This assumption can be changed in sensitivity studies. Here we are concerned mainly with the theoretical distinction between CRTS and non-CRTS suppliers, and therefore, leaving the empirical classification of actual technologies into these two types as an empirical issue. [↑](#footnote-ref-7)
8. For the case of hydroelectricity generation, even though it can be said that the technology exhibits some degree of scale economies in production, the supply behaviour here may not be characterised as oligopolistic. This can be because these suppliers are mostly state owned or state regulated utilities therefore their behaviour is more likely to price taking rather than price setting. Furthermore, production level in this case is not easily controlled as it depends on the natural environment (amount of water stored) rather than simply on market condition. [↑](#footnote-ref-8)
9. This is the so-called ‘dominant versus competitive fringe’ model of strategic interaction often used to describe the supply behaviour of electricity producers in the electricity market (see for example, Wolak, 2007; Bonacina & Gulli, 2007). [↑](#footnote-ref-9)
10. Capital expenditure is assumed to be ‘up-front’ and fixed hence the marginal cost here refers to the short run rather than the long run. [↑](#footnote-ref-10)
11. The convention here is that a lower case letter will be used to denote the percentage change or rate of change of an upper case letter. [↑](#footnote-ref-11)
12. While the impacts of climate change policies are mainly on the marginal cost of *L*-group suppliers, the impacts of (renewable) energy policies, on the other hand, are mainly on the marginal costs of the ‘fringe competitors’ (renewable electricity suppliers). [↑](#footnote-ref-12)
13. The shares are 28.6%, 11.6%, 25.8%, 24.8% and 0.64% respectively in 2007 (2007 is chosen because this is the base year of the GTAP v8 data base). [↑](#footnote-ref-13)
14. However, the emissions levels from CCS technologies are assumed to be 1/10 of the emissions from non-CCS counterparts, see IPCC (2005). [↑](#footnote-ref-14)
15. The value of 51% is the estimated fuel-output ratio for oil technology in Japan in 2007 (authors’ own estimation). [↑](#footnote-ref-15)
16. <http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=2&pid=2&aid=7>. [↑](#footnote-ref-16)
17. In principle, this can also be performed for other regions using the same method as described, but in this study, we concentrate only on the case of Japan. [↑](#footnote-ref-17)
18. We use the GTAP-E model (see Burniaux and Truong (2002)) since this is the simplest global model compatible with the GTAP data base and is often used by many CGE modelers to study the impacts of climate and energy policies. We refer to the modified model as JTAP-E2 (standing for Japan GTAP-E with Electricity sector decomposition). [↑](#footnote-ref-18)
19. In Sue Wing (2008) natural resources are assumed to take up to 20-30% of the value of the capital input in some technologies such as nuclear hydro and other renewable technologies. These ‘fixed-factor’ inputs are taken from the value of capital in the GTAP data base, and the value of capital inputs are adjusted accordingly. In our approach, rather than arbitrarily assigning a proportion of the capital input to this ‘fixed factor’ (to control their supply) we incorporate the limited supply of these resources via the specification of the supply elasticities of these technologies, which are to be estimated from GIS information. [↑](#footnote-ref-19)
20. Note that  and  this means that since for therefore and for  [↑](#footnote-ref-20)
21. The cross-price elasticities are not symmetric because. However, if we replace with andwith where then equation (14) will be symmetric with respect to the (calibrated) . The values of and can then be calculated from calibrated own and (symmetric) cross-price elasticities. [↑](#footnote-ref-21)
22. These values are given in Arora and Cai (2014) for the case of the US which can be assumed to apply also to Japan. In the future, however, empirical values relevant to Japan will need to be used. [↑](#footnote-ref-22)
23. Also following from Arora and Cai (2014), the CES substitution elasticities within the Coatec, Oiltec, and Gastec branches are assumed to be equal to 5, 5, and 10 respectively. [↑](#footnote-ref-23)
24. Arora and Cai (2014) also follow the same procedure. For example, assume that =2.7 for the case of carbon-free technologies, and it is stated that this is consistent with a value of own price elasticities of 2.6 as estimated by Johnson (2014). However, it should be noted that Johnson’s elasticity estimates are for s*upply* rather than demand. [↑](#footnote-ref-24)
25. Since CRESH requires quantity adjustment to ensure the sum of all technology production is equal to the sector output, we present two cases: one *with* and one *without* this quantity adjustment, labeled CRESH (a) and CRESH (b) respectively. [↑](#footnote-ref-25)