A SUPPLY-DEMAND MODEL FOR THE DUTCH GAS SECTOR

Model Documentation

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This documentation describes a simulation model developed to be used in a policy analysis study for the Dutch gas sector. The objective of this policy analysis study is to find policy options that are effective in meeting the conflicting interests of the key actors and robust against uncertainties in the long-term. Focusing on uncertainties, an exploratory modeling approach is adopted in this study, and a system dynamics simulation model is developed with this approach. This simulation model is used as a platform to generate internally consistent and plausible scenarios within the boundaries of the system of interest.

In the first section of this documentation, an overview of the simulation model is presented, and main assumptions about the scope are discussed. The following three sections describe three main segments of the model, namely the supply, demand and market subsystems, respectively. The description of each sub-model in these sections explains both the main assumptions of this sub-model generally, and the formulations of its equations in detail. Lastly, Section 5 concludes this documentation with a brief discussion on the model, and with a reflection on its main assumptions.

1 OVERVIEW OF THE MODEL

This simulation model is based on a system model that conceptualizes the Dutch gas sector in a supply-demand view. Complying with an energy-economy model, this view focuses on the consumer demand on the one hand, the supply sources on the other, and the infrastructure and market balancing these two in the middle. The simulation model includes these three main segments, being the supply, demand and market, excluding the infrastructure because the production infrastructure is included in the corresponding supply sub-model, and the transport infrastructure is not in the scope of this study.

Figure 1 illustrates an overview of the simulation model with the three major sub-models and with the connections between them. These connections are the model variables determined in one of the sub-models, and used in another one. As the figure shows, the supply sub-model produces the production rates and costs of each supply source, which are used in the market sub-model to determine the price. Price-setting in the market reflects the competition between supply sources, as the eventual price value is used in the supply sub-model to determine profitability, and hence further production and the market share of these sources. The price variable is also used in the demand sub-model since consumer demand changes as price changes. The demand volumes determined in this sub-model are used in the market sub-model for price-setting in return, to indicate the effect of the supply/demand balance. Between the supply and demand sub-models, the demand volumes determined in the latter are major factors used in the supply sub-model to determine production rates or import volumes. From the supply sub-model to the demand, the link is the societal acceptance of natural gas production, which determines the demand flow between natural and renewable gas via consumer preference.

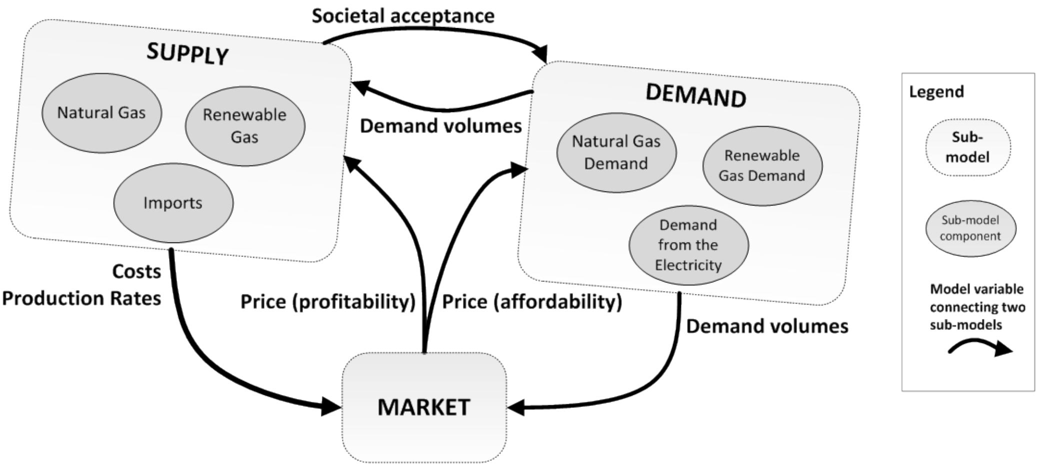


Figure 1: Overview of the simulation model

Being a system dynamics model and considering the national gas sector, this model concentrates on the total or average values of system variables at a high aggregation level. For instance, the production rate of natural gas does not represent the production from a single natural gas field based on a decision of a single producer, but the total production rate from all such fields, based on a decision of the totality of producers, assumed to be a homogenous group. With this homogeneity assumption, this model includes the actions and decisions of several actor groups in addition to the above-mentioned system components, as the drivers of change in the system. Table 1 lists these actors and their actions included in the model.

Table 1: Actors and their actions and decisions included in the simulation model

Actor	Actions/Decision variables
Natural gas producers	Investment in exploration and development Production profile Desired natural gas price
Renewable gas producers	Capacity installation Desired renewable gas price
Traders	Expected market price Import volumes
International traders	Import price
TSO	Import capacity installation
Gas consumers	Natural and renewable gas demand Switching to electricity
Electricity producers	Capacity installation and utilization

The following three sections describe the supply, demand and market segments of the model, respectively, with their sub-models including the actions and decisions of the above-mentioned actors.

2 SUPPLY SIDE

As mentioned before, three main supply sources are taken into account in this study, being the domestically produced natural gas, renewable gas, and imported natural gas. Equation 1 shows the *Total Supply (TS)* in the Dutch gas market as the sum of contributions from these three sources, namely *Total Production Rate of Natural Gas (TPR_{NG})*, *Total Production Rate of Renewable Gas (TPR_{RG})*, and *Total Import Volume (TIV)*. The sections below will describe the model structures corresponding to each of these supply options.

$$TS(t) = TPR_{NG}(t) + TPR_{RG}(t) + TIV(t) \tag{1}$$

2.1 Natural Gas Production[1]

Several system dynamics models that investigate natural gas or petroleum resources exploration and production have been described in the literature (Davidsen *et al.*, 1990; Dyner *et al.*, 1998; Olaya and Dyner, 2008; Chi *et al.*, 2009), which originate from an early model of Naill (1974). The model developed in this study is similar to these models, in terms of the relation between the exploration and production activities and the corresponding investments, and the factors that affect investments such as price and demand. However, this model is different than those in terms of three main aspects: First, a more detailed lifecycle structure of natural gas fields is implemented in this model, as will be explained further below, in order to test policies specific to the Netherlands and to different steps of the extraction process. Secondly, this model includes the societal acceptance of natural gas production and its effects on investments, due to the recent developments in the Netherlands and in the world regarding this issue. Lastly, having the general purpose of focusing on uncertainties to generate a large number of future scenarios, this model includes several parametric and structural uncertainties, i.e. the model formulations representing different assumptions that could be made for the same phenomenon.

Natural gas is extracted from the large Groningen field, and on- and offshore small fields in the Netherlands. These two types of natural gas production are taken into account separately in the model, in order to represent different regulations for these and to be able to test policies specific to each of these. Being a natural gas type with different technological characteristics and cost values, shale gas production is assumed to have the same model representation as the other two types of natural gas, once it is allowed to be produced. The *Production Rates* (*PR*) of these three types of natural gas constitute the *Total Natural Gas Production Rate (TPR_{NG})*, as Equation 2 shows. Technically, these three types of natural gas are denoted with the subscripting feature of Vensim DSS on the same model structure, and they are not explained separately in the sections below, unless necessary. Namely, the equations describing the model do not contain any indices corresponding to these three types, as long as there is no difference between their equations.

$$TPR_{NG}(t) = \sum_i PR_i(t) \quad ; \text{ i = Groningen, small fields, shale} \tag{2}$$

Figure 2 summarizes the main causal relations and loops governing the natural gas production mechanism in the model. In this diagram, an arrow denotes a causal link between two variables, and the sign next to it signifies the polarity of that causal link. If a change in the first variable changes the second variable in the same direction, then the polarity is positive, otherwise it is negative. The

[1] Earlier versions of this model are published in (Eker and van Daalen, 2012), (Eker and van Daalen, 2013a) and (Eker and van Daalen, 2013b).

Depletion Loop is the main loop in the field lifecycle, implying that increased production depletes the reserves, which reduces further production. Regarding the investment of producers to stimulate production (and new discoveries), the Economies of Depletion is a reinforcing loop, which means that depletion due to increasing *Production Rate* increases the unit cost, leading to a price increase which makes the investments in production more attractive. The Economies of Scale loop, however, is a balancing loop which describes the increased production reducing price, which further reduces the investments, and hence the production rate. Lastly, the Market Development loop summarizes the supply-demand relation in the market, where high production decreases the price, and hence increases the demand, which further increases the production. This aspect of the model is further explained in Section 4. The next three sections will describe the natural gas sub-model in three parts, namely the field lifecycle describing the technical system, the economics section explaining the decision making of producers about investments and other economic aspects, and the societal acceptance section describing how this social phenomenon is incorporated into the model.

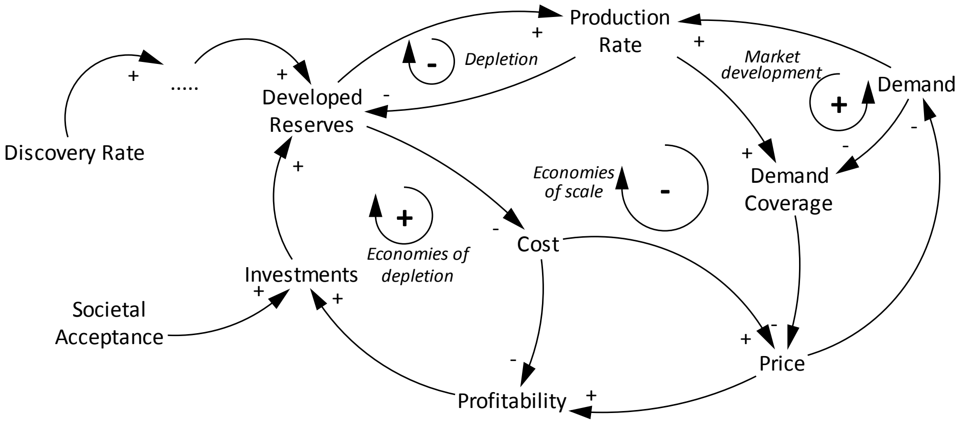


Figure 2: A simplified causal loop diagram of the natural gas production

2.1.1 Field lifecycle of natural gas production

The technical subsystem of natural gas production is modelled based on the field lifecycle which is composed of exploration, appraisal, development and production phases (Jahn *et al.*, 2008), and in correspondence with the resource and reserve terminology of the Society of Petroleum Evaluation Engineers (SPEE, 2002) and the Dutch exploration and production company EBN (EBN, 2013). This terminology includes four categories of resource base, namely *Prospective Resources*, *Contingent Resources*, *Undeveloped Reserves* and *Developed Reserves*, unlike the previous system dynamics models that have only two categories as discovered and undiscovered resources. The reason for this distinction was the delays from discovery to production that can strongly affect the producible volume, and the actions that should be taken at different stages to keep this volume high. These four categories of the resource base are represented by a chain of stock variables as shown in Figure 3, since they accumulate over time as new discoveries and developments flow in or out.

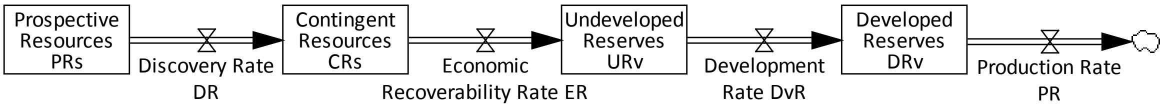


Figure 3: Stock-flow structure of the natural gas production sub-model

Stock variables in the systems dynamics methodology are mathematically the integrals of the summation of the flows that affect them. Equation 3 demonstrates this formulation for the *Developed Reserves (DRv)*, where the inflow of this stock variable is *Development Rate (DvR)* and the outflow is *Production Rate (PR)*. The rest of this section focuses on the formulations of the flow variables.

Besides, the volume unit used in these formulations is billion cubic meters (bcm), where 1 bcm gas has the equivalent calorific value of 1 bcm Groningen gas.

$$DRv(t) = DRv(0) + \int_{t_0}^{t} \left(DvR(\tau) - PR(\tau) \right) d\tau \tag{3}$$

The *Discovery Rate (DR)* is the flow variable representing new natural gas discoveries as a result of exploration activities. As seen in Equation 4, it is formulated as the ratio of *Effective Investment in Exploration (INV^{*}_{exp})*, which is on the scale of billion euros per year, to the *Unit Cost of Exploration (C_{exp})*, which is on the scale of euros per m^3 of gas discovered. The unit cost is a variable that increases over time with respect to the ratio of *Prospective Resources (PRs)* to its initial value (total undiscovered resources) as shown in Equation 5. This increase in the cost reflects the 'creaming effect', which means that as the amount of undiscovered resources declines with discoveries, it becomes more difficult, hence more costly to find new fields. Due to this limitation, the cumulative number of discoveries follows a logarithmic growth pattern, also named 'creaming curve' in the petroleum engineering terminology (EBN, 2012). Therefore, since the change rate of logarithmic growth linearly decreases, the unit cost is assumed to be linearly dependent on the ratio of initial *Prospective Resources (PRs)* to its current value.

$$DR(t) = \frac{INV^{*}_{\exp}}{C_{\exp}(t)} \tag{4}$$

$$C_{\exp}(t) = C_{\exp}(0) \frac{PRs(0)}{PRs(t)} \tag{5}$$

Economic Recoverability Rate (ER) is formulated as a fraction of the *Contingent Resources (CRs)*, which represent the stock of discovered but economically not viable resources. This fraction is a variable depending on the *Profit Percentage of Natural Gas (PP_{NG})* and formulated as the multiplication of a base value of this fraction (ρ_{ER}) and the *Effect of Price on Economic Recoverability ($f_{p,ER}$)* which is an increasing graphical function. Equation 6 denotes these formulations.

$$ER(t) = CRs(t) * \rho_{ER} * f_{p,ER}(PP_{NG}) \tag{6}$$

With economic recoverability, *Contingent Resources (CRs)* become *Undeveloped Reserves (URv)*, which is the group of resources economically viable to extract, but has not been developed yet for production, i.e. there is no infrastructure installed in the field. The *Development Rate (DvR)* represents the rate of conversion from undeveloped to developed reserves with such infrastructure installation and similar activities. It is formulated similar to the *Discovery Rate (DR)*, as the ratio of *Actual Investment in Development (INV^{*}_{dev})* to the *Unit Development Cost (C_{dev})* (Equation 7). Unlike the exploration cost, the development cost is assumed to be constant over time, since the factors that change it, such as rig availability, field location etc., are not included in the scope of this study.

$$DvR(t) = \frac{INV^{*}_{dev}(t)}{C_{dev}} \tag{7}$$

Production Rate (PR) is formulated differently for the Groningen and small fields production, because the Groningen field is given a 'swing producer' position, which implies that the demand is first satisfied by the small fields production, then the Groningen field is used to meet the remaining demand. As seen in Equation 8, *Production Rate of Small Fields (PR_{Sf})* is stimulated by the *Total Natural Gas Demand (TD_{NG})*, which is the sum of domestic (Dutch) natural gas demand and international demand for the Dutch gas. However, with a 'min' formulation, it is limited by the production profile, which is formulated as the ratio of *Developed Reserves* to the *Average Lifetime of*

Small Fields (T_{Sf}). This lifetime parameter actually represents a preference of producers about how long they want to maintain the reserves. *Production Rate of the Groningen Field (PR_{Gr})* is formulated similarly in Equation 9, except that the demand from the Groningen field is the difference between the total demand (TD_{NG}) and the supply from small fields (PR_{Sf}).

$$PR_{Sf}(t) = \min\left(TD_{NG}(t),\ DRv_{Sf}(t)/T_{Sf}\right) \tag{8}$$

$$PR_{Gr}(t) = \min\left(TD_{NG}(t) - PR_{Sf}(t),\ DRv_{Gr}(t)/T_{Gr}\right) \tag{9}$$

2.1.2 Economics of natural gas production

As mentioned before, investments in exploration and development are what stimulates the production of natural gas. As shown in Figure 2, profitability and societal acceptance are the two factors that affect the investments. Additionally, the expected future demand and the availability of resources targeted by the investments, such as the volume of estimated *Prospective Resources*, are two other factors important in the investment decision of producers. This section explains how the effect of these four factors and the eventual investment decisions are formulated, first for the exploration investments, then for the development.

Annual investments both in exploration and production are quantified in billion euros per year. *Intended Investment in Exploration ($IINV_{exp}$)* is the multiplication of a reference amount of investment, namely *Normal Intended Investment in Exploration (INV^0_{exp})* and the effects of three factors being the *Effect of Prospects on Exploration ($f_{exp,PRs}$)*, *Effect of Profitability on Investments (f_{pr})*, and *Effect of Societal Acceptance on Investments (f_{SA})* (Equation 10). All of these three effects have a positive impact on the investments, and they are formulated with increasing graphical functions. The inputs of these functions are normalized *Estimated Demand Coverage of Prospective Resources (C_{PRs})*, *Profit Percentage of Natural Gas Production (PP_{NG})*, and *Societal Acceptance (SA)*, respectively, as shown in Equations 11-13. While the last two of these inputs will be explained later, *Estimated Demand Coverage of Prospective Resources (C_{PRs})* is formulated as in Equation 14, indicating for how long the current value of *Prospective Resources* meet the domestic natural gas demand (D_{NG}), if it remains the same. Although the three graphical functions are approximately determined for the base case and they are highly uncertain, Figure 4 shows their initial (base case) forms.

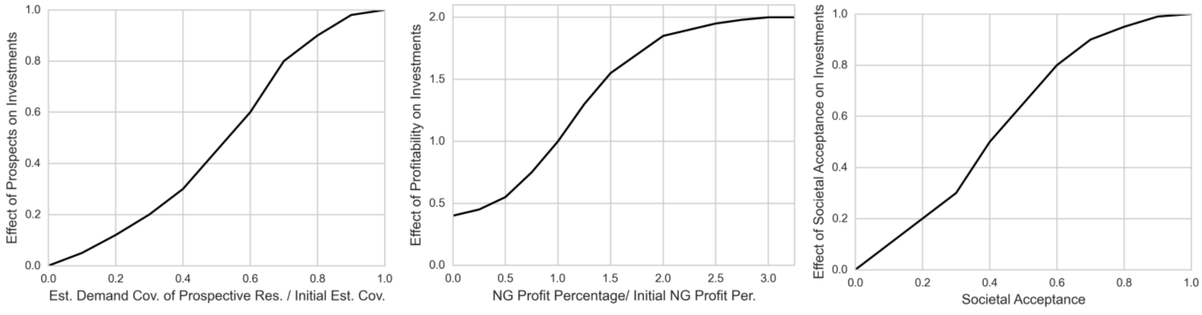
$$IINV_{\exp}(t) = INV^0_{\exp} * f_{\exp,PRs}(t) * f_{pr}(t) * f_{SA}(t) \tag{10}$$

$$f_{\exp,PRs}(t) = f_{\exp,PRs}\left(C_{PRs}(t)/C_{PRs}(0)\right) \tag{11}$$

$$f_{pr}(t) = f_{pr}\left(PP_{NG}(t)/PP^0_{NG}\right) \tag{12}$$

$$f_{SA}(t) = f_{SA}\left(SA(t)\right) \tag{13}$$

$$C_{PRs}(t) = PRs(t)/D_{NG}(t) \tag{14}$$



(a) *Prospects* **(b)** *Profitability* **(c)** *Societal Acceptance*

Figure 4: Graphical functions showing the effects of three factors on Exploration Investments

In addition to the above formulation for intended investment, *Actual Investment in Exploration* (*$AINV_{exp}$*) reflects the effect of requirement for exploration (to be able to meet future demand) on the investments. For this effect, producers are assumed to follow a stock-control approach. In other words, it is assumed that producers try to maintain a certain volume of *Contingent Resources,* hence make their decisions based on a required exploration rate. To define the required exploration rate, the stock management structure of Sterman (2000, p. 668) is adopted. In this structure, *Required Discovery Rate (DR_{req})* is modeled as the sum of an adjustment for the stock variable (*Contingent Resources*) and an expected loss rate in this stock, as denoted by Equation 15. The first part of this element shows the stock adjustment, as the first order delay of the nonnegative difference between the initial and current *Contingent Resources*, where d_{Adj} is the *Adjustment Delay*. The second part is the expected loss rate of this stock, which a first order information delay of its outflow, namely the *Economic Recoverability Rate (ER)*. Vensim's SMOOTH function is used to represent this information delay (Ventana, 2009).

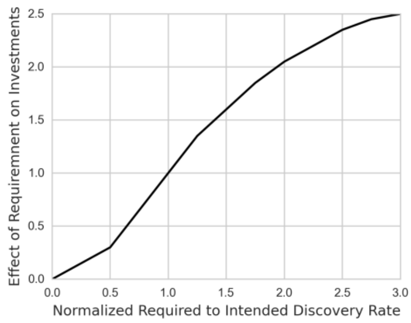
$$DR_{req}(t) = \frac{\max\left(CRs(0) - CRs(t),\ 0\right)}{d_{Adj}} + \text{SMOOTH}\left(ER(t),\ d_{Adj}\right) \tag{15}$$

The effect of required discoveries on investment is determined with respect to the ratio of required to intended discovery rate. *Intended Discovery Rate* is the division of *Intended Investment in Exploration ($IINV_{exp}$)* by the *Unit Cost of Exploration (C_{exp})* as in Equation 16. As shown in Equation 17, *Actual Investment in Exploration ($AINV_{exp}$)* is the multiplication of *Intended Investment in Exploration ($IINV_{exp}$)* by an increasing function of which the input is the normalized ratio of required to intended discovery rate. The base run shape of this function is shown in Figure 5. Since the discoveries take time, there is a delay between the actual investments, and the effective investments that determines the discovery rate. Therefore, *Effective Investment in Exploration (INV^*_{exp})* used in Equation 4 is formulated with a first order material delay, i.e. *Actual Investment in Exploration ($AINV_{exp}$)* divided by the discovery delay (d_{dis}).

$$DR_{int}(t) = IINV_{exp}(t) / C_{exp}(t) \tag{16}$$

$$AINV_{exp}(t) = IINV_{exp}(t) * f_{req}\left(DR_{req}(t) / DR_{int}(t)\right) \tag{17}$$

Figure 5: Graphical function showing the effect of requirement on exploration investments



This model structure for the decision making of producers on exploration investments is used also for the development investments with a few differences. The first difference is the absence of the effect of prospects, hence *Intended Investment in Development* covers only the effect of profitability and societal acceptance on the normal investment level. However, since producers do not invest if there are no reserves in the 'undeveloped' category, *Actual Investment in Development* includes the effect of available *Undeveloped Reserves.* The third difference is the formulation of *Required Development Rate*. This variable is also formulated with a stock management approach, as in the case of *Required Discovery Rate*, yet the desired level of the stock variable for adjustment is determined differently. This desired level was the initial value of *Contingent Resources* for discoveries, assuming that producers aim to maintain this level, but for development, it is assumed to be the multiplication of the current production rate by the desired lifetime of the reserves. This assumption is based on the assumption that producers aim to maintain the current production rates for a particular duration of time.

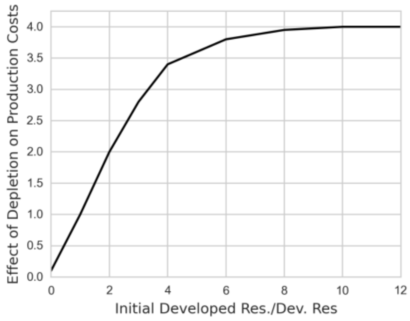
Regarding the economics of natural gas production, in addition to investments, two other model mechanisms are the calculation of costs and how producers determine their desired price to be influential in the market price-setting. These two components of the model will be described below briefly.

The *Total Unit Cost (TUC_{NG})* of natural gas production has three components, being the exploration cost, development cost and production cost. For the exploration and development cost of one unit og gas extracted immediately from the *Developed Reserves,* it must be noted that these are not equal to the unit costs of exploration and development *(C_{exp} and C_{dev})* because of the delays between exploration and production. The effect of these delays is modeled with a co-flow structure explained in Appendix 1, and the average development cost and average exploration cost of one unit of developed reserves is added to the *Unit Production Cost (C_{prod})* as shown in Equation 18. As for the production cost, it is based on a well-known phenomenon in the natural gas production, which is the increase in the production costs as the reserves deplete, due to decreasing reservoir pressure and production becoming more difficult. This increase in the cost is formulated in the model with respect to the ratio of *Developed Reserves* to its initial value, and with an increasing function as shown in Equation 19 and Figure 6, where C^{*}_{prod} is the reference production cost. This formulation is based on two assumptions: According to the ideal gas law, under constant (reservoir) volume and temperature, a change in the amount of gas inversely affects the pressure, hence the rate of decline in the amount of gas is equal to the rate of decline in reservoir pressure, and the rate of cost increase to replace this pressure. However, producers do not continuously invest in increasing this pressure when the amount of remaining gas is very low (Jahn et al., 2008, p.123). Therefore, the function in Figure 6 saturates as the ratio of initial gas to the remaining one increases.

$$TUC_{NG}(t) = C_{prod}(t) + C_{dev,DRv}(t) + C_{exp,DRv}(t) \tag{18}$$

$$C_{prod}(t) = C^{*}_{prod} * f_{prod,DRv}\left(DRv(0)/DRv(t)\right) \tag{19}$$

Figure 6: Graphical function showing the effect of depletion on the production costs



Once the *Total Unit Cost* is determined in the abovementioned way, the *Profit Percentage of Natural Gas Production (PP_{NG})* is the ratio of net unit profit to the unit costs, as denoted in Equation 20 where p_{market} is the market price of natural gas, and TUT_{NG} is the tax paid by the producers per unit of natural gas sold. This unit tax is a percentage of the unit profit as seen in Equation 21, where τ_{NG} is the total tax percentage for natural gas production, including the corporate income tax and the State Profit Share (SPS). Based on this unit tax, *Total State Revenue from Natural Gas Production (Rev_{NG})* is computed as the sum of tax amounts collected for each gas type, namely the multiplication of unit tax and the corresponding production rate (Equation 22).

$$PP_{NG}(t) = \frac{p_{market}(t) - TUC_{NG}(t) - TUT_{NG}(t)}{TUC_{NG}(t)} \tag{20}$$

$$TUT_{NG}(t) = \tau_{NG}\left(p_{market}(t) - TUC_{NG}(t)\right) \tag{21}$$

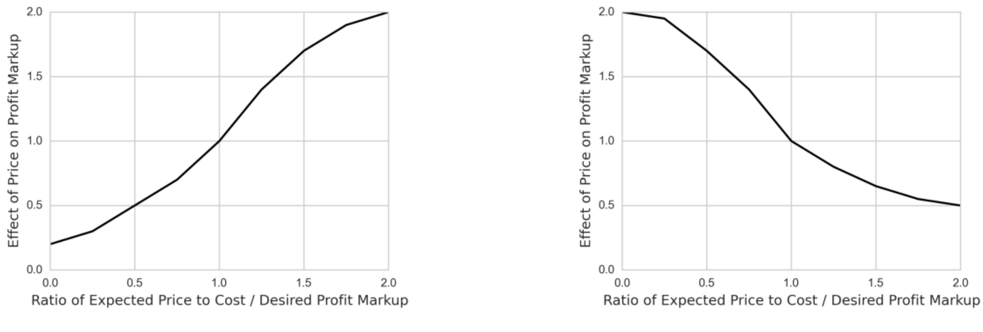
$$\mathrm{Re}\,v_{NG}(t) = \sum_i TUT_{NG,i}(t) * PR_i(t)\,; \quad i = \text{Groningen, small fields, shale} \tag{22}$$

Natural gas producers set a desired markup on the *Total Unit Cost*, which influence the price-setting in the market between the traders and producers, with the effect of demand coverage as will be explained later in Section 4. The formulation of this *Desired NG Price* (DP_{NG}) (Equation 23) is an example of structural uncertainty, because three alternatives can be thought of about how the producers decide on the profit markup, but there is no evidence about which one represents the reality better. These three options are incorporated to the model with a switch structure, namely the *Producer Price Structure Switch (PPSS)*. The first option (*PPSS*=0) is a constant markup value (PM^*_{NG}), which sets the desired price to the multiplication of the unit costs and a markup value which does not change over time, as in Equation 24. The second option (*PPSS*=0.5) assumes that producers are eager to obtain more profit as the market price increases, and set increasing markup values as the price expectations increase. Equation 24 shows that this increase in the profit markup is formulated with a graphical function, of which the input is the normalized ratio of expected market price to the total unit cost ($R^*_{p,c}$). Lastly, the third option (*PPSS*=1) assumes that producers are careful and reduce their desired profit markup as the market price declines, to prevent a reduction in demand. This formulation is also shown in Equation 24, with a different graphical function but the same input variable. The base case shapes of these two graphical functions can be seen in Figure 7.

$$DP_{NG}(t) = TUC_{NG}(t) * \left(1 + PM_{NG}(t)\right) \tag{23}$$

$$PM_{NG}(t) = \begin{cases} PM^*_{NG} & ;\ PPSS = 0 \\ PM^*_{NG} * f_{PM,inc}\left(R^*_{p,c}(t)\right); & PPSS = 0.5 \\ PM^*_{NG} * f_{PM,dec}\left(R^*_{p,c}(t)\right); & PPSS = 1 \end{cases} \tag{24}$$

$$R^*_{p,c}(t) = \frac{p^*_{NG}(t) / TUC_{NG}(t)}{PM^*_{NG}} \tag{25}$$



(a) $f_{PM,inc}$ **(b)** $f_{PM,dec}$

Figure 7: Graphical functions showing the two alternative effects of price on the profit markup

2.1.3 Societal acceptance of natural gas production

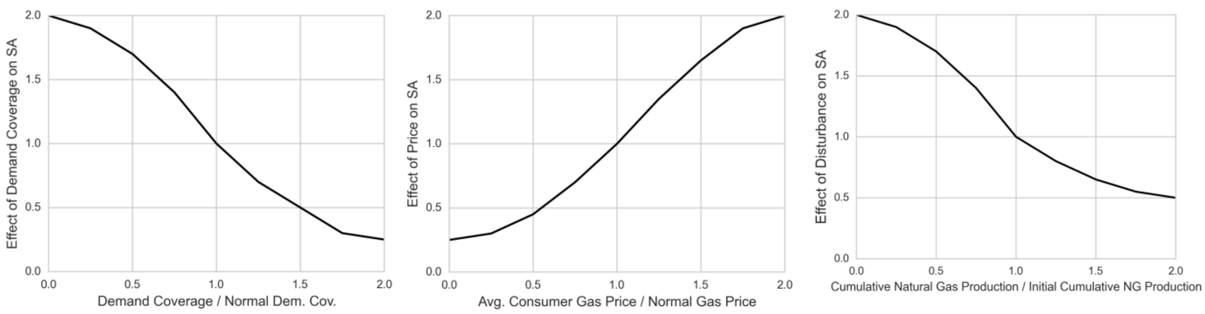
Societal acceptance is included in the model with a simple structure that can function as an indicator of public opinion about natural gas production (of each type). Therefore, the *Societal Acceptance* variable, which is assumed to take values between 0 and 1, does not directly refer to an actual measurable notion, such as the percentage of population that is in favor of natural gas etc. For the formulation of *Societal Acceptance (SA)*, it is assumed that public opinion is formed as a cumulative effect of related events, and an information delay formulation is used, where *SA* is a stock variable. In this formulation seen in Equation 26, the net flow is assumed to be the difference between the *Expected SA (SA*)* and the current *SA*, divided by the *Reaction Delay* (d_{SA}). To ensure that *SA* remains between 0 and 1, the *Expected SA* is limited with min and max functions as in Equation 27. *Indicative Expected SA* (ISA^*) is the variable which reflects the effect of three factors on *SA* in a multiplicative formulation with nonlinear graphical functions, as shown in Equation 28. These three effects are the *Effect of Demand Coverage on SA* ($f_{Dc,SA}$), *Effect of Prices on SA* ($f_{Pr,SA}$) and *Effect of Disturbance on SA* ($f_{Dist,\,SA}$).

$$SA_i(t) = SA_i(0) + \int_{t_0}^{t} \frac{SA^*(\tau) - SA(\tau)}{d_{SA}}\, d\tau \tag{26}$$

$$SA^*(t) = \min\Big(\max\big(ISA^*(t),\, 0\big),\ 1\Big) \tag{27}$$

$$ISA^*(t) = SA(t) * f_{Dc,SA}(t) * f_{Pr,SA}(t) * f_{Dist,SA}(t) \tag{28}$$

Effect of Demand Coverage on SA is a decreasing function of (perceived) demand coverage of natural gas, i.e. the ratio of total gas supply in the Netherlands to the total gas demand. Low demand coverage implies a scarcity of gas, and it is assumed to increase the acceptance of natural gas because the energy need should be satisfied. *Effect of Prices on SA* is an increasing function of a normalized value of *Average Consumer Gas Price*. It is based on the assumption that more consumers develop a positive opinion about more natural gas production, as the prices increase and their purchase power of gas decreases. The third effect, which is that of ‘disturbance’ on SA, represents the decline in societal acceptance as production causes incidents such as earthquakes, environmental or landscape damage. Therefore, *Effect of Disturbance on SA* is formulated as a decreasing function of a normalized value of *Cumulative Natural Gas Production*, which is the accumulation of annual production rates. This assumption was based on the finding that earthquakes in Groningen are dependent on cumulative production (Muntendam-Bos and De Waal, 2013). Being based on approximations, these effect functions are highly uncertain, yet their base run forms are shown in Figure 8 below as an example.



(a) *Demand Coverage* **(b)** *Price* **(c)** *Disturbance*

Figure 8: Graphical functions showing the effects of three factors on *Societal Acceptance*

2.2 Renewable Gas Production[2]

This sub-model’s core structure is the production chain from biomass to biomethane at the national level. In this chain shown in Figure 9, both biomass supply is shared between heating, electricity generation and biogas production. Similarly, biogas supply is shared between electricity production, heating and upgrading sectors. This is how the local biomass is utilized in the Netherlands; therefore

[2] This section is published as a part of (Eker and van Daalen, 2015).

the production of biofuels for transport is excluded from the model. The biomass types used or that can be used for biomethane production in the Netherlands are manure and other agricultural waste products, sewage sludge, landfill gas, industrial waste water and household waste (vegetables, fruit and garden waste). These are grouped into two, as wet and dry biomass with average gas yield and heating values for each group, and matched with biogas production or other end-use technologies accordingly.

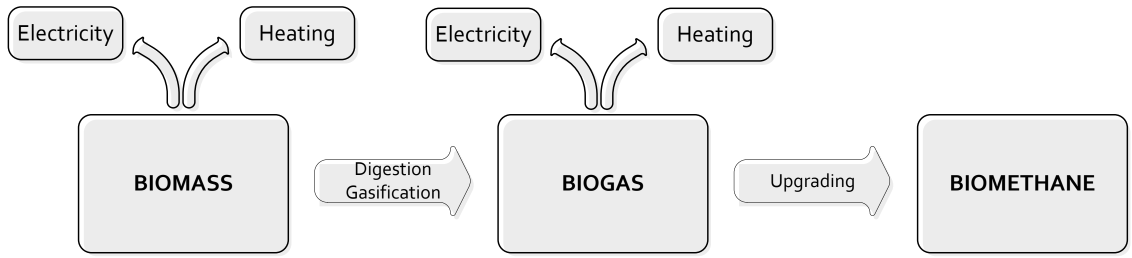


Figure 9: Production chain of biomethane

There are two technologies for producing biogas from biomass, namely *digestion* that uses wet biomass, and *gasification* that uses dry biomass. As in the case of different natural gas types, these two technologies of biogas, and then biomethane, production are taken into account separately in the model, with similar market and capacity construction mechanisms but different parameter values for costs, biogas yields and subsidies, by using the subscripting feature of Vensim DSS. Therefore, *Total Production Rate of Renewable Gas (TPR_{RG})* is composed of two *Production Rates* shown in Equation 29, corresponding to two technologies.

$$TPR_{RG}\left(t\right)=\sum_{j}PR_{RG,j}\left(t\right)\ ;\ \text{j = digestion, gasification} \tag{29}$$

Biomethane is produced in a decentralized manner, and this feature raises the question of where to inject it into the gas grid. It can be injected into the distribution or transmission grid, right after production or after being collected in a hub, or it can be stored. Depending on the selected options, the gas grid may be reshaped in future, for example in a decentralized way. However, this model focuses on production and excludes spatial dynamics of the infrastructure. In other words, in the model it is assumed that all biomethane produced can be used for a useful final purpose.

The production chain structure is derived from a generic commodity market model (Sterman, 2000, p. 798-824) where production is dependent on resource availability, installed capacity and demand, and capacity installation is dependent on expected resource availability, expected demand and price. These relations will be detailed in the next two sub-sections that describe biogas and biomethane production mechanisms.

2.2.1 Biogas production

The causal loop diagram in Figure 10 illustrates the relationships between the main elements of the biogas production model and the feedback loops formed by these relationships. In the model, *Biogas Production Rate*, which is the volume of gas produced each year, is dependent on two factors: *Biogas Demand* and *Biomass Allocated for Biogas,* which is the resource availability constraint on production. *Biogas Production Rate* is also restricted by the *Biogas Production Capacity*, but since *Biomass Allocated for Biogas* is not more than the capacity can accommodate, this restriction is already included in the resource availability. The variables *Biogas Production Rate, Biogas Production Capacity* and *Biomass Allocated for Biogas* are subscripted by two technologies, namely digestion and gasification, to represent the individual values of these variables for each technology.

The Market Development loop is formed by the fundamental relations between supply, demand and price. As *Biogas Production Rate* increases, a large supply with respect to demand reduces the price, and a lowered price increases the demand. Expected demand for biogas determines the desired production capacity, which triggers further capacity installation if it is higher than the current installed capacity. Installed *Biogas Production Capacity*, together with *Biogas Demand*, determines *Biomass Allocated for Biogas*. Additionally, biomass is pulled into the biogas market as its availability stimulates production, which increases demand and results in higher installed capacity that demands more biomass. This positive loop formed via *Biogas Demand* is called Pull Loop. However, as increased supply due to biomass availability for biogas increases *Biogas Production Rate* and reduces price, the biogas sector becomes less attractive for biomass use compared to heating and electricity, and less biomass is allocated for biogas production. These relations form the negative feedback loop called Shooting Yourself. Although they are not shown in the diagram, other negative feedback loops included in the model are due to the obsolescence mechanism of the production capacity and the increased price in response to increased demand.

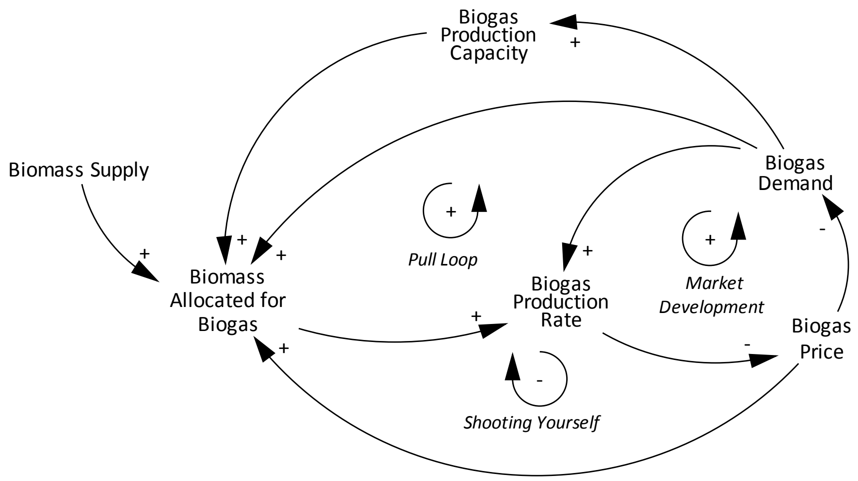


Figure 10: Causal loop diagram for biogas production

Wet biomass is allocated between biogas production via digestion and electricity generation in Combined Heat and Power (CHP) units. Dry biomass is allocated between biogas production via gasification, heating, and electricity generation by co-firing in coal power plants and in CHP units. The basis of the allocation mechanism is the biomass demand and financial attractiveness of these sectors, and it is translated into equations as follows: In Equation 30, *Initial Wet Biomass Allocated for Biogas ($IBMS_{W,BG}$)* is the minimum of *Wet Biomass Demand of the Biogas* sector ($BMSD_{W,BG}$) and a fraction of *Wet Biomass Supply (BMS_W)*. This fraction ($\theta_{W,BG}$) which symbolizes the attractiveness value is determined by the ratio of *Wet Biomass Value for Biogas (p_{BG}^{wbms})* to the sum of this and *Wet Biomass Value for Electricity (p_E^{wbms})*, as in Equation 31. *Wet Biomass Value for Biogas (p_{BG}^{wbms})* is the price ultimately obtained in the biogas sector for each unit of biomass, and formulated as the multiplication of *Biogas Price (p_{bg}^*)* and *Average Biogas Yield of Wet Biomass (y_w)* as seen in Equation 32.

$$IBMS_{W,BG}(t) = MIN\left(BMSD_{W,BG}(t),\, BMS_W(t)\theta_{W,BG}(t)\right) \tag{30}$$

$$\theta_{W,BG}(t) = \frac{p_{BG}^{wbms}(t)}{p_{BG}^{wbms}(t) + p_E^{wbms}(t)} \tag{31}$$

$$p_{BG}^{bms}(t) = p_{bg}^{*}(t)\, y_w \tag{32}$$

Biomass Demand of Biogas (both wet and dry), as well as that of the electricity sector, is assumed to be dependent on the installed capacity. *Biomass Demand of Heating* is assumed to change fractionally for simplicity, and this fraction is assumed to be a step function in time. The heat generated in biomass-based CHP's is assumed to replace heat generated by biomass, and reduced from *Biomass Demand of Heating.* Similar to the *Biomass Demand, Biogas Demand* is the sum of demand from heating, upgrading and electricity sectors, which are modeled similarly.

Biogas Production Capacity (BG_C) is the accumulation of annual installation activities and loss due to obsolescence, both for digestion and gasification, as formulated in Equation 33. Since installation delay is short, accumulation of capacity under construction is not taken into account in this model. The *Installation Rate* (IBG_C) in Equation 34 is assumed to be a percentage of *Desired Installation Rate* (IBG_C^*), where this percentage is denoted by *Investment Response to Profitability* (IRP_{BG}). IRP_{BG} (Equation 35) is formulated as an increasing function (f_{BG}^I) of *Profit Percentage of Biogas* (PP_{BG}). *Desired Installation Rate* (IBG_C^*) is the nonnegative discrepancy between the *Desired Biogas Capacity* (BG_C*) and current *Biogas Production Capacity* (BG_C) divided by the *Installation Delay* (d_I), as seen in Equation 36; and BG_C* is assumed to be equal to the *Expected Total Biogas Demand* (ED_{BG}), which is the sum of biogas demand from electricity, heating and biomethane production sectors. *Obsolescence Rate* (OBG_c) is determined by a single negative feedback loop mechanism, and its formula shown in Equation 37 is BG_C divided by the *Average Lifetime of Biogas Plants* (d_T^{BG}).

$$BG_C(t) = BG_C(0) + \int_{t_0}^{t} \left(IBG_C(\tau) - OBG_C(\tau) \right) d\tau \tag{33}$$

$$IBG_C(t) = IBG_C^*(t)\, IRP_{BG}(t) \tag{34}$$

$$IRP_{BG}(t) = f_{BG}^I\left(PP_{BG}\right) \tag{35}$$

$$IBG_C^*(t) = \frac{MAX\left(0,\, BG_C^*(t) - BG_C(t)\right)}{d_I} \;\; ; \;\; BG_C^*(t) = ED_{BG}(t) \tag{36}$$

$$OBG_C(t) = \frac{BG_C(t)}{d_T^{BG}} \tag{37}$$

Being a new technology, the production costs of biogas via both digestion and gasification are expected to decline over time due to the *Learning Effect*(L_{bg}) as *Cumulative Production*(C_{bg}) increases. This learning effect is formulated as in Equation 38, following Sterman (2000, p.507). Therefore, *Variable Unit Cost of Biogas Production* (VUC_{bg}) is calculated as in Equation 39, as the sum of production costs (PC_{bg}) reduced by a learning effect (L_{bg}) and fuel costs (FC_{bg}), which is the price of biomass per unit of gas. *Unit Investment Cost of Biogas* (IUC_{bg}) is calculated by spreading the investment cost of a capacity unit (IC_{bg}) over the potential production throughout the lifetime (d_T^{BG}) with the equivalent annual cost (EAC) formula based on the *Interest Rate (r),* as seen in Equation 40.

$$L_{bg}(t) = \left(\frac{C_{bg}(t)}{C_{bg}(0)} \right)^{-l_{bg}} \tag{38}$$

$$VUC_{bg}(t) = FC_{bg}(t) + PC_{bg} L_{bg}(t) \tag{39}$$

$$IUC_{bg} = \frac{IC_{bg}\, r\, (1+r)^{d_T^{BG}}}{\left((1+r)^{d_T^{BG}} - 1 \right)} \tag{40}$$

Biogas Price (p_{bg}), which actually does not exist since there is no market for biogas where it is traded in this form, is a variable in the model used to represent the effect of profitability on investments and the fuel costs of technologies that use biogas. The value of biogas is determined by its producers and consumers, as the multiplication of *Desired Biogas Price* (DP_{bg}) by the *Effect of Demand Coverage on Biogas Price* ($f_{bg}{}^{D}$) in Equation 41. (Note that this effect function is similar to the one used for the natural gas price, as it will be explained later in Section 4.) A profit mark-up (PM_{bg}) dependent on the ratio of biomethane price to the unit cost of biogas is added to the total unit cost of biogas production (TUC_{bg}) to represent the desired price of producers (DP_{bg}) as seen in Equation 42. (It must be noted that the total unit cost is the sum of variable and investment costs shown in Equations 39 and 40)

$$p_{bg}(t) = DP_{bg}(t)\, f_{bg}^{D}(t) \tag{41}$$

$$DP_{bg}(t) = TUC_{bg}(t)\left(1 + PM_{bg}(t)\right) \tag{42}$$

2.2.2 Biomethane production

Biomethane production is modeled almost the same as biogas production, except that the resource for production, which was biomass for biogas, is replaced by biogas for biomethane, and the demand is replaced by the renewable gas demand of consumers (households, industry, agriculture, transport). Figure 11 shows how biogas supply stimulates the biomethane market and further demand for biogas, which also illustrates how Figure 10 and Figure 12 are connected through *Biogas Production Rate* and *Biomethane Production Capacity* variables.

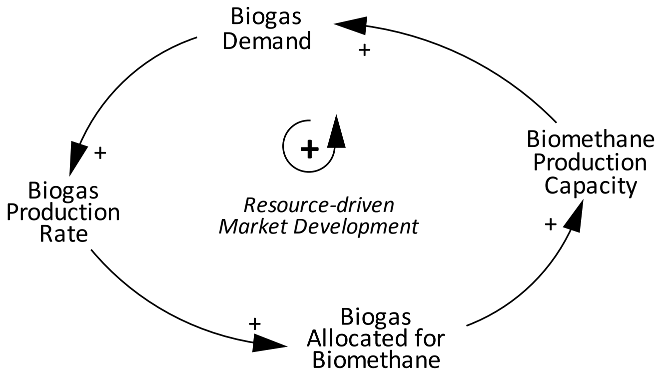


Figure 11: Resource-driven Market Development Loop for Biomethane

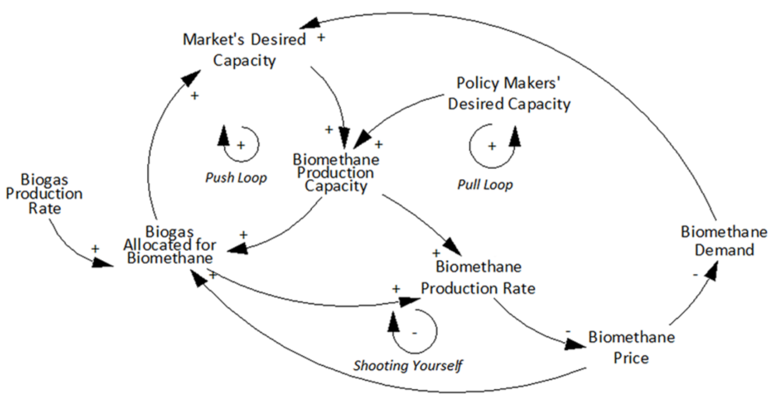


Figure 12: Causal Loop Diagram for Biomethane Production

As Figure 12 illustrates, *Biomethane Production Rate (PR_{RG})* is determined by two factors, and it is formulated as the minimum of these (Equation 43), namely the *Biomethane Production Capacity* and

Producible Biomethane, which depends on *Biogas Allocated for Biomethane* (BG_{bm}) and the upgrading efficiency (u_{bm}).

$$PR_{RG}(t) = \min\left(BM_C(t),\ BG_{bm}(t) * u_{bm}\right) \tag{43}$$

The causal loop diagram of the biomethane production model in Figure 12 is almost the same as that of Figure 10, because the same framework of resource, capacity, production and demand interaction has been applied. However, the major difference is the effect of policy on capacity construction. The Dutch government has an ambition to inject 3 billion cubic meters (bcm) biomethane per year into the gas grid by 2020, as shown in Figure 13. Therefore, besides providing subsidies, government agencies and related distribution and transmission system operators (DSO's and TSO's) actively support producers in capacity installation projects to realize this goal. Attributed to this policy-driven mechanism of capacity installation, two types of desired capacity are defined in the model, and the actual installation rate is assumed to be the minimum of the two desired installation rates determined by these two desired capacity levels. *Market's Desired Capacity (MBM_C^*)* is assumed to be the minimum of *Expected Producible Biomethane* (EBM_R) which indicates the expected resource availability, and *Expected Total Renewable Gas Demand* (ED_{RG}) which is dependent on the renewable gas demand determined in the demand sub-mopdel. *Market's Desired Installation Rate* of biomethane production capacity ($MIBM_C^*$) is formulated as the nonnegative difference between the market's desired and current *Biomethane Production Capacity* (BM_C) divided by the *Installation Delay* (d_I). Equations 44 and 45 belong to these two formulations.

$$MBM_C^*(t) = MIN\left(EBM_R(t), ED_{RG}(t)\right) \tag{44}$$

$$MIBM_C^*(t) = \frac{MAX\left(MBM_C^*(t) - BM_C(t), 0\right)}{d_I} \tag{45}$$

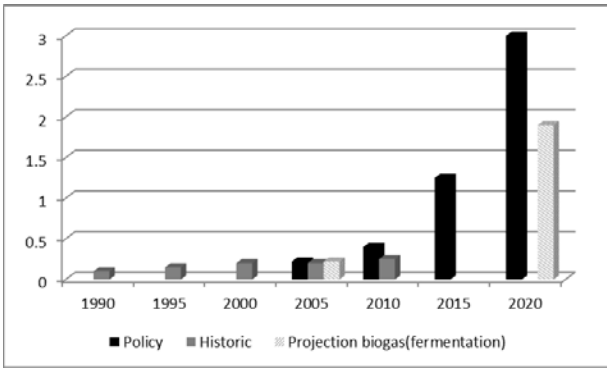


Figure 13: Biomethane targets - Source: (Scheepers, 2013)

Policy Makers' Desired Capacity is assumed to be an increasing function approximated to the goals specified in Figure 13, starting from nearly zero in 2000 and increasing to 3 bcm in 2020 with an annual increase fraction of 27%. After 2020, it is assumed that policy makers adjust this goal depending on the level of achievement. Therefore, a floating goal mechanism (Sterman, 2000, p. 532-535) is implemented as seen in Figure 14 and Equations 46 and 47, in which the *Desired Capacity of Policy Makers* (PBM_C^*) is formed by the accumulation of difference between *Goal Change Rate* (GCR_{BM}^{2020}) which increases the desired capacity until 2020 and *Adjustment Rate of Biomethane Capacity Goal* (AR_{BM}) which is effective after 2020. AR_{BM} is formulated as the discrepancy between the desired (PBM_C^*) and actual (BM_C) biomethane upgrading capacity, divided by the Goal Adjustment Time (d_{AR}), so that the values of the actual capacity lower than the desired capacity result in a reduction in the goal and vice versa.

$$PBM_C^*(t) = PBM_C^*(0) + \int_{t_0}^{t} \left(GCR_{BM}^{2020}(\tau) - AR_{BM}(\tau) \right) d\tau \tag{46}$$

$$AR_{BM}(t) = \frac{PBM_C^*(t) - BM_C(t)}{d_{AR}} \tag{47}$$

2.2.3 Producers' decision making

Eventually, the desired installation rate of the biomethane production capacity is the maximum of the market's and policy makers' desired installation rates; whereas the actual installation rate is a fraction of this eventual desired installation rate, as shown in Equation 48. This fraction is called the biomethane producers' *Investment Response to Profitability (IRP_{BM})*, and it represents how producers make a decision for capacity installation. The formulation developed for this decision making exemplifies a structural uncertainty, because two alternative formulations are possible, and taken into account. Depending on the value of *Producers' Decision Structure Switch (PIDS)* as shown in Equation 49, IRP_{BM} is determined by an assessment of producers either based on a net present value (NPV) calculation, hence a long-term view, or based on the current profitability of biomethane production, hence a short-term view.

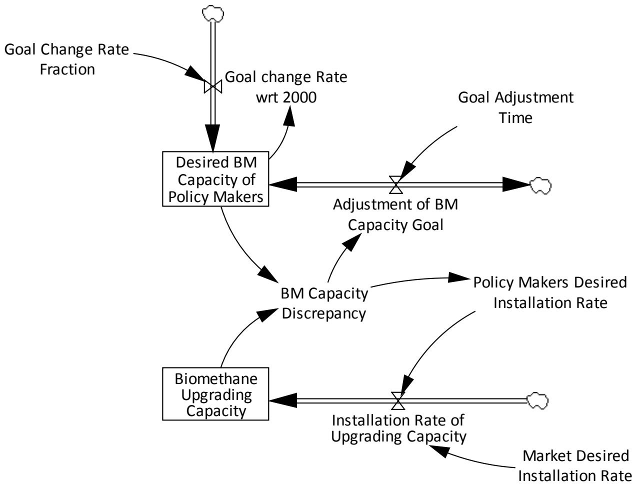
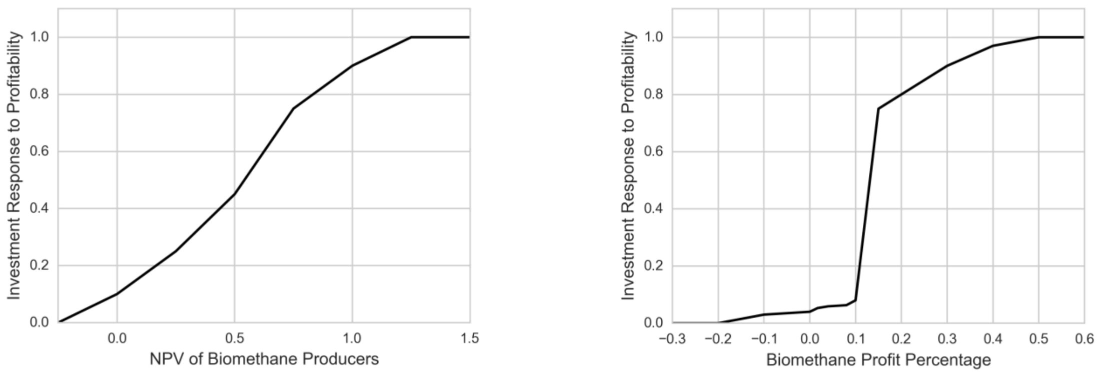


Figure 14: Floating Goal of the Policy Makers for Biomethane Upgrading Capacity

$$IBM_C(t) = IBM_C^*(t)\, IRP_{BM}(t) \tag{48}$$

$$IRP_{BM}(t) = \begin{cases} f_{IRP}^{npv}\left(NPV_{BM}(t)\right); & PIDS = 0 \\ f_{IRP}^{prf}\left(PP_{BM}(t)\right); & PIDS = 1 \end{cases} \tag{49}$$

Both of these alternative formulations involve a graphical function, namely f_{IRP}^{npv} and f_{IRP}^{prf}, which are both increasing functions since the installation increases as the profitability increases. Although the form and values of these functions are highly uncertain, their base run shapes are shown in Figure 15.



(a) *Based on NPV* **(b)** *Based on Profit Percentage*

Figure 15: Graphical Function for the Investment Response to Profitability of Biomethane Production

As for the two different indicators of profitability, the *Profit Percentage of Biomethane* (PP_{BM}) shown in Equation 50 is the ratio of the unit profit of biomethane production, i.e. the difference between the current price (p_{bm}) and the total unit cost (TUC_{bm}), to the unit cost. It must be reminded that both TUC and p_{bm} are formulated similar to those of biogas, except that p_{bm} includes a subsidy, if applicable. While this formulation only considers the profitability at the time of decision making about installation, the NPV-based one takes the profitability of next 12 years. Although it is shorter than the lifetime of a biomethane plant, this duration is selected because the government's subsidy calculations are based on a 12-year project lifetime. The NPV of unit biomethane produced is calculated as in Equation 51 with r_{bm} being the rate of return, and ENI_i being the *Expected Net Income* of producers in i years ahead. The projection of future values is kept in an array by using the subscripting feature of Vensim DSS, hence the summation as in the actual NPV calculation rather than an approximation was possible.

$$PP_{BM}(t) = \frac{p_{bm}(t) - TUC_{bm}(t)}{TUC_{bm}(t)} \tag{50}$$

$$NPV_{BM}(t) = \sum_{i=1}^{i=12} \frac{ENI_i(t)}{(1+r_{bm})^i} \tag{51}$$

Expected Net Income of each year in the 12-year lifetime is the difference between *Expected Producer Price* and *Net Costs* as seen in Equation 52.

$$ENI_i(t) = EPP_i(t) - NC_i(t) \tag{52}$$

Expected Producer Price is dependent on the subsidy scheme provided by the government. In the no-policy case, it is assumed that the current subsidization scheme continues, and *EPP* is formulated as the maximum of *Expected Market Price* ($EMP_{bm,i}$) in i years ahead and the *Basis Price* (BP_{bm}) determined by the government, which is the price producers receive if their cost is higher than the market price but remains the same for 12 years (Equation 53). *Expected Market Price* is formulated with the FORECAST function which extrapolates the *Biomethane Market Price* (p_{bm}) i years ahead based on the data of last 5 years (Equation 54).

$$EPP_i(t) = \max\left(EMP_{bm,i}(t), BP_{bm}(t)\right) \tag{53}$$

$$EMP_{bm,i}(t) = \text{FORECAST}\left(p_{bm}(t), 5, i\right) \tag{54}$$

Net Costs (NC_i) is formulated as in the calculations made by the Netherlands Energy Research Center (ECN, 2014) for advising the government on subsidization. The components of this cost value are the operations and management cost, tax amount and an annual equivalent of the investment cost. The exact formulation of this variable can be found in Appendix 2.

2.3 Imports

The last supply option included in the model is the imported natural gas. This section explains the model structure representing the import decision of traders. There are three main assumptions that require mentioning before a description. Firstly, natural gas is imported to the Netherlands in two ways: In the gaseous form via pipelines from Russia and Norway, and as Liquefied Natural Gas (LNG) from various countries (e.g. Algeria) to the Gate Terminal in the Port of Rotterdam. The model includes these two types of imports separately, with the same structure but subscripted variables as in the case of different gas types in the previous sections. The description below will focus on the common structure and not include these subscripts, unless necessary.

The second main assumption is that the import volumes in this model represent the net imports, because it is assumed that natural gas is imported only when the total domestic gas production is not adequate to cover the total annual demand. In other words, only the imports of natural gas used domestically are taken into account in this study as 'import'. Also, only the domestically produced natural gas is assumed to be exported, as long as there is surplus not used in the domestic market. The volume of gas enters the Dutch grid and transported to the neighboring countries is called 'transit'. Figure 16 depicts these gas flows, whereas Table 2 summarizes the definition of two key variables, namely the *Import Volume* and *Total Import Volume*.

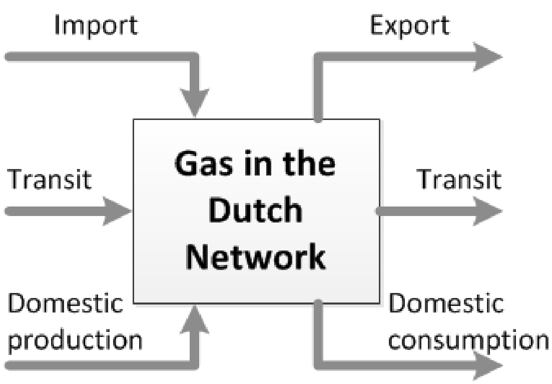


Figure 16: Main gas flows in the Dutch gas grid

Table 2: Definition of the key model variables in the import sub-model

Variable	Definition
Total Import Volume	The total volume of natural gas imported as LNG and via pipelines, to cover the difference between the domestic production and the domestic demand
Import Volume (= net imports)	The volume of gas imported via one of the import means, i.e. LNG or pipelines. It is a fraction of the Total Import Volume.

The third assumption relates to the volume measure, and as in the case of small fields or renewable gas, the volume of imported gas is measured in Groningen-equivalent billion cubic meters.

Import Volume (IV) is the key variable in this sub-model and it represents the annual volume of imported natural gas. The three factors that affect this volume are depicted in Figure 17, as the availability of gas on the international market (*Import Availability*), the entry capacity of the border infrastructure (*Import Capacity*) and the *Import Demand*, which includes the effect of supply discrepancy and the price on imports. These relations will be detailed in the formulations below.

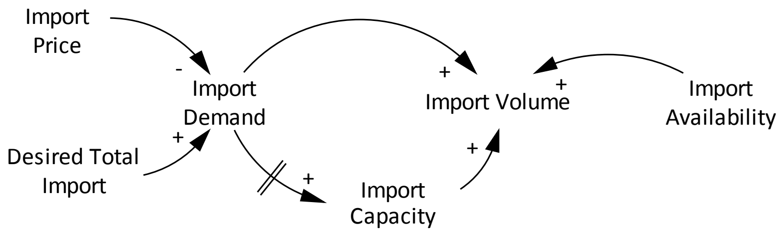


Figure 17: The main factors affecting the *Import Volume*

Equation 55 shows the formulation of *Import Volume*, assumed to be the minimum of *Import Demand* (*ID*) and *Possible Import Volume(IV$_{pbl}$)*. *Import Demand* represents the annual volume demanded by each import mean (gaseous or LNG), and it is formulated as a fraction of the *Desired Total Import (TIV*)* as in Equation 56. *TIV** is the nonnegative discrepancy between the *Total Domestic Gas Production (TPR)*, which is the sum of total natural and renewable gas production, and *Total Domestic Gas Demand* (*TD*) as shown in Equation 57. As for the fraction, it is named *Smoothed Fraction of Import Mean (ρ^*_{imp})* and its formulation can be seen in Equation 58. The reason for using a smooth function with the delay time d_{mp} is the information delay between the price change and the effect of this on the import demand. The actual fraction is determined based on the relative price of importing gas by each import mean. In other words, the fraction of gaseous import in covering the *Desired Import Volume* is the ratio of the price of importing gas via LNG ($p_{imp,LNG}$) to the sum of prices of each import mean. Note that this inversion between the fraction and price is because high prices of an import mean makes it less attractive, as high prices of gaseous import creates a higher market share for LNG.

$$IV(t) = \min\left(ID(t),\ IV_{pbl}(t)\right) \tag{55}$$

$$ID_i(t) = TIV^*(t) * \rho^*_{imp,i}(t)\ ; \quad \text{i = gaseous, LNG} \tag{56}$$

$$TIV^*(t) = \max\left(TPR(t) - TD(t),\ 0\right) \tag{57}$$

$$\rho^*_{imp,i}(t) = \text{SMOOTH}\left(\frac{p_{imp,i^-}(t)}{\left(p_{imp,i^-}(t) + p_{imp,i}(t)\right)},\ d_{mp}\right) \tag{58}$$

Import Price ($p_{imp,i}$) represents the price paid to foreign suppliers in the international market. Certainly, this international trading is subject to the basic market rules, and the price increases if demand increases. (Increase in supply due to a price increase in the Dutch market will be discussed later, regarding the *Import Availability*.) Although the dynamics of the international market is beyond the scope of this study, the change in the *Import Price* with respect to a change in the import demand of the Netherlands is taken into account. However, this market mechanism is subject to many uncertainties, and hence, a simple model structure, which can represent the uncertainties parametrically, is preferred. Appendix 3 explains this structure, i.e. the formulation of *Import Price* in detail.

Possible Import Volume(IV$_{pbl}$) represents two limitations on the imports, such as *Import Availability* (*IA*) (the gas available for the Netherlands on the international market) and *Import Capacity (Imp$_C$)*. Hence, it is formulated as the minimum of these two factors, as Equation 59 shows. *Import Availability* is assumed to be a fraction of the total gas available on the international market that the Netherlands can potentially import, which is called *Import Potential (IP)*. The *Import Potential* parameter is not the total production amount of the producers from which the Netherlands can import, but it is an indicator of what the Netherlands can maximally import given the demand of others. This maximum amount is reduced by the *Political Restriction Fraction* ($\rho_{imp,pol}$) and the *Fraction of*

Potential Imports for the Netherlands ($\rho_{imp,pr}$) which shows the attractiveness of the Dutch market for the internationally available gas. While the former is assumed to be a constant, the latter fraction is formulated with a negative exponential function, which is a common choice for simple resource allocation structures (Sterman, 2000, p. 545). Since a fraction cannot be greater than 1, the exponential function is converted to be a logarithmic function as seen in Equation 61, meaning that the fraction of potential gas that can be imported to the Netherlands saturates around 1, as the market price in the Netherlands becomes too high compared to the international market price. This *Relative Market Price (RMP)* is denoted in Equation 62 as the ratio of *Import Price* in the Dutch market to the *Average Price in the International Market (p_{intl})*, which is assumed to be a constant in this study.

$$IV_{pbl}(t) = \min\left(Imp_C(t),\, IA(t)\right) \tag{59}$$

$$IA(t) = IP * \left(1 - \rho_{imp,pol}\right) * \rho_{imp,pr}(t) \tag{60}$$

$$\rho_{imp,pr}(t) = 1 - \mathrm{e}^{-RMP(t)} \tag{61}$$

$$RMP(t) = p_{imp}(t) / p_{intl} \tag{62}$$

The last part of the import sub-model to be explained is the capacity installation. *Import Capacity (Imp_C)* is a stock variable in the model which represents the total entry capacity of the Dutch gas grid (not only for the 'imports' as defined in this study, but also for exports and transit). This variable increases with *Import Capacity Installation Rate (IR_{imp})* and decreases with *Import Capacity Obsolescence Rate (OR_{imp})*, as Equation 63 shows. For simplicity, the installation procedure is not detailed with more stock variables including capacity planned, commissioned, under construction etc. Instead, the delays caused by these steps are summed in *Import Capacity Commissioning Delay (d_{imp})* in the formulation of installation rate. Equation 64shows this formulation, as a fraction ($\rho_{com,i}$) of *Total Desired New Capacity ($TImp^*_C$)* for each import mean, divided by the commissioning delay. As for the *Obsolescence Rate*, it is the division of the installed capacity by the *Average Lifetime of Import Capacity*.

$$Imp_C(t) = Imp_C(0) + \int_{t_0}^{t} \left(IR_{Imp}(\tau) - OR_{Imp}(\tau)\right) d\tau \tag{63}$$

$$IR_{Imp,i}(t) = \frac{\rho_{com,i}(t) * TImp^*_C(t)}{d_{imp,i}}; \qquad \text{i=gaseous,LNG} \tag{64}$$

Total Desired New Capacity is the nonnegative difference between the total installed capacity and *Expected Import Demand (EID)* (Equation 65), where expected demand is formulated as smoothed annual *Import Demand*.

$$TImp^*_C(t) = \max\left(EID(t) - \sum_i Imp_{C,i}(t),\, 0\right) \tag{65}$$

As for the fraction of each import mean in installation of new capacity to cover this discrepancy, it is formulated as the relative attractiveness of each mean, where this attractiveness depends on the costs and potentially available import amount of each. Namely, Equation 66 presents this fraction ($\rho_{com,i}$) as the ratio of the attractiveness measure of each import mean ($\delta_{com,i}$) to the sum of these measures. (Note that this formulation is a general resource allocation formulation also used in the renewable gas model for the allocation of biomass and biogas resources.) The attractiveness measure has a multiplicative formulation combining the *Effect of Costs on Installation* ($f_{imp,cost}$) and the *Effect of Availability on Installation* ($f_{imp,av}$), as shown in Equation 67. As in Equation 61, a negative exponential formulation is chosen for this effect function. Since the causality between the costs and installation is negative, a decreasing function is used for this formulation, whereas an increasing logarithmic function is preferred for the positive effect of availability on installation. Equation 68 and 69 show these formulations, having the *Total Unit Cost of Imports (TUC_{imp})* and *Expected Import Availability* (*EIA*) as the inputs, respectively. *Total Unit Cost of Imports* is the sum of the *Import Price* (of which formulation is shown in Appendix 3), and a fixed cost representing the infrastructure costs. *Expected Import Availability* is a forecast of the *Import Availability* discussed in Equation 60, formulated with the FORECAST function of Vensim. These two variables are normalized with respect to a reference value for each (TUC^*_{imp} and EIA^*) to be used as an exponent.

$$\rho_{com,i}(t) = \delta_{com,i}(t) \Big/ \sum_i \delta_{com,i}(t) \tag{66}$$

$$\delta_{com}(t) = f_{imp,cost}(t) * f_{imp,av}(t) \tag{67}$$

$$f_{imp,cost}(t) = e^{-TUC_{imp}(t) / TUC^*_{imp}} \tag{68}$$

$$f_{imp,av}(t) = 1 - e^{-EIA(t) / EIA^*} \tag{69}$$

3 DEMAND SIDE

There are five major groups of gas consumers in the Netherlands, being households (including commercial and public buildings), agriculture, industry, transport and the electricity generation sector. The first four of these can use both natural and renewable gas provided by the natural gas grid, whereas the electricity sector uses biogas, not renewable gas (biomethane), for power generation. In other words, natural gas is demanded by five sectors including the electricity sector, whereas renewable gas is demanded by only the four of these sectors. Therefore, the *Total Domestic Gas Demand* (*TD*) in the Netherlands is the sum of *Total Natural Gas Demand except Electricity ($TD_{NG,ee}$), Natural Gas Demand from the Electricity Sector ($D_{NG,e}$)* including a reduction due to cogeneration of heat and power, and *Total Renewable Gas Demand (TD_{RG})*, as seen in Equation 70.

$$TD(t) = TD_{NG,ee}(t) + D_{NG,e}(t) + TD_{RG}(t) \tag{70}$$

The electricity sector lies at the core of the energy transition, and the future role of natural gas in this sector is highly uncertain, hence the gas demand from this sector is highly uncertain. Therefore, the electricity sector is modeled in more detail in this study, with the competition between several technologies yielding the share of natural gas in the power mix, whereas the demand from other sectors is modeled with a simpler structure, which is the same for all consumer groups. The two sections below explain these sub-models, first for the electricity sector, then for the other sectors.

3.1 Natural Gas Demand of the Electricity Sector[3]

In the Netherlands, the electricity sector is currently dominated by gas-fired generation because natural gas has been an abundant and reliable source for decades, leading to an accumulation of natural gas power plants. However, while the transition to a renewable energy system is expected to moderate the share of the natural gas in the power sector on the one hand, the intermittent nature of renewable energy production requires a flexible backup source on the other hand. Natural gas is considered as a strong candidate to be the substitute of intermittent renewable electricity due to its relatively low CO_2 emissions and flexible operation, which may give a different role to gas in the future. Yet, coal-fired and nuclear power technologies are still important competitors of gas, due to lower fuel prices and almost zero CO_2 emissions, respectively. Thus, due to such developments in the power sector which are important for the future of gas demand and supply, electricity generation is explicitly modeled in this study.

[3] This section is partially published in (Eker and van Daalen, 2013a).

The total power generation capacity installed in the Netherlands in 2010 is reported as 25.4 GW, which yielded 123.8 TWh electricity in that year (Energiezaak, 2011). This current capacity contains a wide variety of technologies and resources, although their shares in the power mix significantly differ. Table 3 lists the technologies included in the model and their installed capacity, and capacity under construction values in 2010.

Table 3: Electricity Generation Capacity in the Netherlands in 2010

Type	Installed Capacity	Capacity under construction
Biogas	0.216 GW (Panoutsou and Uslu, 2011)	0
Biomass	1.214 GW (Panoutsou and Uslu, 2011)	0
Coal	3.6 GW (EFNL, 2011)	4.5 GW (EFNL, 2011)
Coal with CCS	0 GW	0
Natural gas	10.5 GW (Enipedia, 2010; CBS, 2012)	5 GW (EFNL, 2011)
Decentral natural gas	5.55 GW (CBS, 2012)	0
Natural gas with CCS	0 GW	0
Nuclear	0.5 GW (EFNL, 2011)	1.6 GW (EFNL, 2011)
Solar	0.088 GW (CBS, 2013)	0
Wind	2.24 GW (CBS, 2013)	2 GW (EFNL, 2011)

All these 10 power generation sources are assumed to have the same capacity installation, market and operation structure with different parameter values, and the model is based on the two negative feedback loops demonstrated in Figure 18. The *Capacity installation decision* loop represents the decision making of producers about commissioning new capacity, according to the discrepancy between current supply level and the expected demand, and the *Technology Score*, which is calculated based on the profitability of each technology under the current market conditions and the societal acceptance level. The second loop, *Annual production decision*, represents the adjustment of the capacity utilization factor according to the share in the power mix and profitability, which determines the desired production of each technology based on the expected demand value. The model structure behind these two loops will be described in more detail below, in the corresponding two sections.

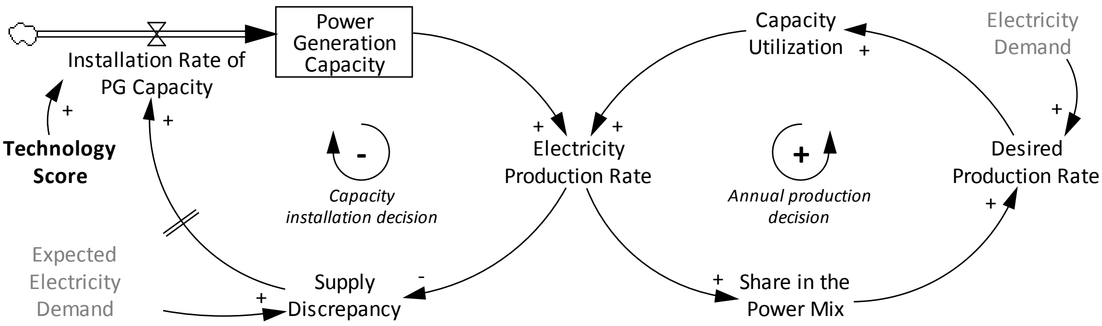


Figure 18: Overview of the electricity generation model

3.1.1 Capacity installation

As shown in Figure 18, *Power Generation Capacity* is represented by a stock variable that increases with new installations and decreases by obsolescence (not shown in the figure for simplicity). *Installation Rate* of each technology is dependent on the *Supply Discrepancy* and *Installation Fraction* which is a fraction that distributes the expected supply discrepancy among the technology options for capacity installation. *Supply Discrepancy* is the nonnegative difference between the total electricity production (sum of all technologies) and the expected electricity demand. *Installation Fraction (ρ_E)* is the ratio of the *Technology Score (S)* of each electricity generation technology to the sum of all such scores (Equation 71).

$$\rho_{E,i}(t) = \frac{S_i(t)}{\sum_k S_k(t)}; \quad \text{k = biogas, biomass, coal, natural gas, ...} \tag{71}$$

The score of each technology (*S*), is assumed to be the weighted average of the profitability and societal acceptance of this technology, with uncertain weights depending on the preferences of decision makers. This formulation can be seen in Equation 72. (Note that the weights sum up to 1.)

$$S(t) = w_{pr} P_E(t) + w_{SA} SA_E(t) \tag{72}$$

The *Profitability* of an electricity generation technology (P_E) is determined by the costs and the market price of this technology, with two alternative structures discussed for the investment decision of biomethane producers (Section 2.2) and shown in Equation 49. These alternative structures involved the same graphical functions both for the NPV-based alternative and the one based on profit percentage, and the NPV and profit percentage of each electricity technology is calculated similarly as explained in Section 2.2. However, the cost calculation of electricity technologies differs from the costs of biomethane, because the CO_2 price is taken into account, as well as the natural gas and biogas prices which are internal variable elements of this model. These factors affect the *Total Variable Cost (TVC_E)* of electricity, which is one of the components of *Total Unit Cost*, or 'simple levelized cost' of electricity.

As Equation 73 shows, *TVC* is the sum of *Variable Operation and Maintenance Costs (VC_{OM}), CO_2 Cost* (VC_{CO2}) and *Fuel Cost (VC_{fuel}). O&M Costs* (Equation 74) include the reducing effect of learning depending on the cumulative production, which is formulated similar to that of biogas costs as in Equation 38, hence create a reinforcing loop between production and costs. *CO_2 Cost* is the carbon price paid for each ton of CO_2 emitted during the production of one unit of electricity by a generation technology. Therefore, its formulation which can be seen in Equation 75 is the multiplication of the *CO_2 Price* (p_{CO2}) and *Average CO_2 Emission (e_{CO2})*, which is a different value for each technology. *CO_2 Price* is assumed to be a constant over time. As for the *Fuel Cost*, it is assumed to be an uncertain constant for technologies such as biomass, coal and nuclear as seen in Equation 76, and zero for wind and solar energy, yet a variable value for biogas and natural gas, whose prices are determined in the other segments of this model. This fuel price (p_{fuel}) is the conversion of the price value determined per volume unit to a value per energy unit. In Equation 77, this is exemplified for natural gas, where the consumer price of natural gas for electricity sector ($p_{consumer,E}$, see Equation 106) is divided by the calorific value of natural gas (W_{NG}) and the fuel efficiency (eff_{NG}) to yield the price electricity producers pay for unit electricity produced.

$$TVC_E(t) = VC_{OM}(t) + VC_{CO_2}(t) + VC_{fuel}(t) \tag{73}$$

$$VC_{OM}(t) = VC_{OM}^{*} * L_E(t) \tag{74}$$

$$VC_{CO_2}(t) = p_{CO_2} * e_{CO_2} \tag{75}$$

$$VC_{fuel}(t) = \begin{cases} c_{fuel,k} & ;\ \text{k = biomass, coal, coalCCS, nuclear} \\ 0 & ;\ \text{k = wind, solar} \\ p_{fuel,k}(t) & ;\ \text{k = biogas, natural gas, decentral gas, gasCCS} \end{cases} \tag{76}$$

$$p_{fuel,NG}(t) = p_{consumer,E}(t) / (W_{NG} * eff_{NG}) \tag{77}$$

The second factor in determining the score of each technology (S) is *Societal Acceptance*. As in the case of natural gas, the public opinion about controversial technologies such as coal, nuclear and Carbon Capture and Storage (CCS) is assumed to affect the investments in capacity installation. *Societal Acceptance* of electricity (SA_E) is modeled similar to that of natural gas explained in Section 2.1, except that the *Effect of CO_2 Emissions on SA* ($f_{CO2,SA}$) is added to the multiplicative formulation in Equation 28. For this formulation, it is assumed that not being able to meet the CO_2 targets set by the EU and adopted by the Dutch government reduces the societal acceptance of CO_2-intense technologies such as coal and natural gas. Therefore, this effect is formulated with a decreasing S-shaped graphical function, of which input is the ratio of total CO_2 emissions due to electricity production to the target emission levels.

3.1.2 Annual Electricity Production

Having explained the decision making mechanism of electricity producers on capacity installation, this section explains the shorter-term decision on annual electricity production, i.e. the capacity utilization decision of producers, based on the reinforcing loop shown in Figure 18. As this figure shows, the two factors affecting the *Electricity Production Rate* (PR_E) are the installed capacity and *Capacity Utilization (CU)*, and the production rate is the multiplication of these two, as shown in Equation 78. However, it must be noted that for the biogas and biomass technologies, the production amount is restricted by the amount of these resources allocated for electricity production as explained in Section 2.2. *Fuel Availability* (A_{fuel}) used to represent this restriction in Equation 78 is the conversion of biomass and biogas amounts to electricity units with the calorific value and fuel efficiency of each.

$$PR_{E,k}(t) = \begin{cases} \min\left(CU_k(t) * PGC_k(t),\ A_{fuel,k}(t)\right) & ;\text{ if } k = \text{biogas, biomass} \\ CU_k(t) * PGC_k(t) & ;\text{ otherwise} \end{cases} \tag{78}$$

Capacity Utilization (CU) depends on the *Desired Production Rate* (PR^*_E) of each technology, and is formulated with an increasing graphical function of which the input is the ratio of desired to possible production rate, i.e. *Power Generation Capacity (PGC)*. In this formulation shown in Equation 79, the graphical function (f_{CU}) is mostly linear, implying that all desired production is actually produced, but it saturates and converges to one since *Desired Production Rates* higher than the capacity cannot be fully accommodated. As for the *Desired Production Rate*, it is formulated as a fraction of total *Electricity Demand*, where this fraction is the *Expected Share in the Power Mix* (s^*) of each technology, as shown in Equation 80. This variable represents the expectations of producers on their share in the market in the coming year, and is assumed to be a smoothed value of the current *Share in the power Mix (s)*. Equation 81 formulates the *Share in the power Mix* as the ratio of *Production Rate* of a technology to the total electricity production rate.

$$CU(t) = f_{CU}\left(PR^*_E(t) / PGC(t)\right) \tag{79}$$

$$PR^*_E(t) = s^*(t) * D_E(t) \tag{80}$$

$$s_k(t) = \frac{PR_{E,k}(t)}{\sum_k PR_{E,k}(t)} \tag{81}$$

3.1.3 Natural gas demand

The main purpose of this electricity generation model was to derive the natural gas demand of the power sector. This demand value ($D_{NG,e}$) shown in Equation 82 is the difference between the *Natural Gas Demand for Electricity Production* ($D^{pr}_{NG,e}$) and *Demand met by Cogeneration* (D_{cog}) in Combined Heat and Power units, because this heat production utilized in homes or district heating systems substitutes natural gas that would have been demanded otherwise. The volume of gas demanded for electricity production ($D^{pr}_{NG,e}$) is formulated as in Equation 83. In this equation, the *Production Rate* of each technology that uses natural gas is divided by the corresponding fuel efficiency (*eff*) to obtain the electricity-equivalent of natural gas consumption, and then the sum of these is divided by the calorific value of natural gas (W_{NG}) to obtain the natural gas demand in volume unit. It must be noted that since all natural gas demand of the electricity sector is assumed to be satisfied, the consumption and demand values are used interchangeably. As for the *Demand met by Cogeneration*, heat generated per unit of electricity in CHP units by the combustion of natural gas (h_E), which is assumed to be constant, is multiplied by the *Production Rate*. This electricity-equivalent of the heat generated is divided by the calorific value of natural gas to obtain the volume of natural gas saved (Equation 84).

$$D_{NG,e}(t) = D^{pr}_{NG,e}(t) - D_{cog}(t) \tag{82}$$

$$D^{pr}_{NG,e}(t) = \left(\frac{PR_{E,gas}(t)}{eff_{gas}} + \frac{PR_{E,gasDecentral}(t)}{eff_{gasDecentral}} + \frac{PR_{E,gasCCS}(t)}{eff_{gasCCS}} \right) \frac{1}{W_{NG}} \tag{83}$$

$$D_{cog}(t) = \frac{h_e * PR_{E,gasDecentral}(t)}{W_{NG}} \tag{84}$$

3.2 Natural and Renewable Gas Demand except the Electricity Sector[4]

As mentioned at the beginning of Section 3, the natural and renewable gas consumers, excluding the electricity generation sector, are grouped into four in this study. These groups refer to the consumption of gas in the households (including the commercial and public buildings), and by the industry, agriculture and transport sectors. Therefore, the simulation model includes 4 separate sectors for both natural and renewable gas demand, corresponding to these 4 consumer groups. These four sectors are represented by the same structural elements but different parameter values, by using the subscript feature of Vensim DSS, as in the previously described sub-models.

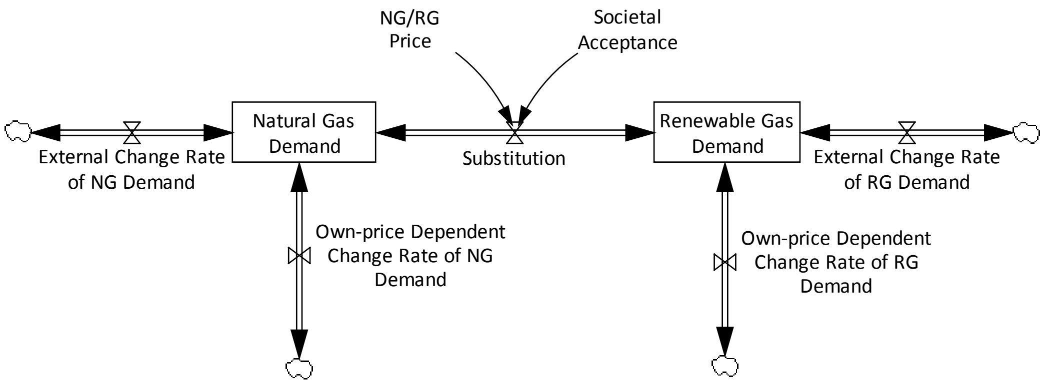


Figure 19: Simplified stock-flow diagram of the demand segment of the model

The two key stock variables of this sub-model are *Natural Gas Demand* (D_{NG}) and *Renewable Gas Demand* (D_{RG}), which represent the annual demand for these two types of gas in terms of billion cubic meters of Groningen equivalent gas per year. The summation of these variables over the four demand groups yield the *Total Natural Gas Demand except Electricity* ($TD_{NG,ee}$) and *Total Renewable Gas Demand* (TD_{RG}). Each of the stock variables for natural and renewable gas demand are assumed to be determined by two flow variables representing the net annual change rate due to price changes and external factors such as consumption trends, in addition to the substitution between them. An overview

[4] This section is partially published in (Eker and van Daalen, 2015).

of this model structure is depicted in the simplified stock-flow diagram in Figure 19. The three flow variables representing the three important factors affecting the annual demand will be discussed in the paragraphs below.

3.2.1 Own-price Dependent Change Rate

The *Own-price Dependent Change Rate (ODCR)* indicates the change in the consumption behavior of consumers due to a price change, and it is formulated based on the concept of price elasticity of demand. Equation 85 shows the formulation of *ODCR* for renewable gas, where D_{RG} is the *Renewable Gas Demand*, and $\rho_{OD,RG}$ is the annual percentage change in *Renewable Gas Demand* due to a price change. This percentage change is formulated as the multiplication of the *Price Elasticity of Renewable Gas Demand* (e_{RG}) and the annual change in the *Biomethane Price* (p_{bmt}), but since consumers do not change their behaviour immediately, the actual change rate is formulated with an information delay. The 'smooth' function of Vensim DSS is used to represent this information delay, where the delay time is *Own-Price Demand Adjustment Delay* (d_{ODCR}) as shown in Equation 86. The same formulation is used for natural gas, with corresponding variables and the elasticity parameter. Appendix 4 explains how this formulation is derived from the elasticity definition.

$$ODCR_{RG}(t) = D_{RG}(t)\,\rho_{OD,RG} \tag{85}$$

$$\rho_{OD,RG} = SMOOTH\left(e_{RG}\,\frac{p_{bmt}(t) - p_{bmt}(t-1)}{p_{bmt}(t-1)},\quad d_{ODCR}\right) \tag{86}$$

The concept of elasticity is well-studied in the economics literature, and a constant elasticity value is seen improper in many cases, since the response of consumers to a price change may be dependent on where this price change occurs on a spectrum of affordable price values. Besides, from a system dynamics point of view, it can be argued that this formulation aggregates many factors such as the availability of substitutes or the purchasing power of consumers into a single parameter value, and does not thoroughly represent the real mechanism of demand response to price change. However, this simple formulation with an elasticity parameter is preferred in this study, due to the importance given to simplicity in exploratory modeling and the ability to capture various scenarios with different values of this uncertain parameter.

The response to price changes, hence the value of the elasticity parameter, varies among the demand sectors. For instance, the households are assumed to have a higher elasticity value than the industry, because small consumers can easily save some heat in the residential consumption or switch to electricity, whereas large consumers require a certain amount of energy to maintain their economic activities such as manufacturing.

Lastly, it must be noted that since *ODCR* represents the annual change rate in demand, the change in price is also determined on an annual basis. Hence, the percentage change in price at time t is calculated with respect to the price value of one year ago.

3.2.2 External Change Rate

External factors affecting the demand change, such as income effect or energy need, are aggregated as an 'external' change rate of both natural and renewable gas demand. A formulation similar to those own-price dependent change rate is used, where the annual *External Change Rate* ($EXCR_{RG}$) is a fraction of the demand, as shown in Equation 87. This fraction ($\rho_{EX,RG}$) is a highly uncertain parameter, and it is assumed to change its value in three periods of the simulation horizon. Namely, it is formulated as a step function, where the parameter value changes in 2012 (after the past data is used between 2000 and 2012), 2025 and 2035, as exemplified in Figure 20. In the model, this is represented by four different parameters, and the last three ones representing the change rates after 2012 are uncertain. This demand change fraction could as well be assumed to be an uncertain constant without a stepwise formulation. However, this step-wise formulation is thought to better represent the uncertainty in such a long horizon as 50 years by incorporating the potential changes over time.

$$EXCR_{RG}\left(t\right)=D_{RG}\left(t\right)\rho_{EX,RG} \tag{87}$$

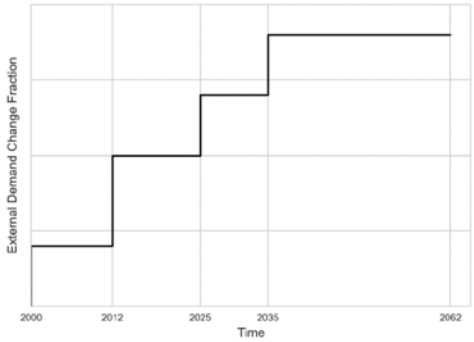


Figure 20: An example step function for *External Demand Change Fraction* ($\rho_{EX,RG}$)

3.2.3 Substitution Rate

Currently in the Netherlands, renewable gas (biomethane) is sold to end consumers based on a certification system. Producers are certified to be able to inject biomethane into the grid, and consumers can subscribe to the 'green' option instead of natural gas if they are willing to pay extra. Following this, the substitution of natural gas by biomethane is, or expected to be, a key factor in determining both natural and renewable gas demand. This substitution is assumed to depend on the relative price of the two options and the societal acceptance of natural gas.

The formulation of the substitution rate between natural gas (NG) and renewable gas (RG) demands is an example of model structure uncertainty, since there are two alternative formulations which are based on two microeconomic concepts that can be used for this phenomenon. The first one is based on the "cross-price elasticity", defined as the percentage change in the demand of a good with respect to 1% change in the price of another good (Png, 2013, p.72). Derived from this definition, *Substitution Rate of NG due to RG Price Change* ($SR_{NG,RG}$) is defined as in Equation 88, whereas Equation 89 shows the change in the RG demand due to NG price change. In these equations, $e_{NG,RG}$ and $e_{RG,NG}$ are cross-price elasticities of natural to renewable gas, and renewable to natural gas, respectively, and p_{NG} and p_{bmt} denote the natural and renewable gas prices. *Substitution Rate due to the Societal Acceptance of NG* (SR_{SA}) is formulated similarly, as in Equation 90, and the total substitution rate (SR), which is assumed to be the shift from RG to NG, is obtained from the summation in Equation 91.

$$SR_{NG,RG}\left(t\right)=D_{NG}\left(t\right)e_{NG,RG}\frac{p_{bmt}\left(t\right)-p_{bmt}\left(t-1\right)}{p_{bmt}\left(t-1\right)} \tag{88}$$

$$SR_{RG,NG}\left(t\right)=D_{RG}\left(t\right)e_{RG,NG}\frac{p_{NG}\left(t\right)-p_{NG}\left(t-1\right)}{p_{NG}\left(t-1\right)} \tag{89}$$

$$SR_{SA}\left(t\right)=D_{NG}\left(t\right)e_{NG,SA}\frac{SA\left(t\right)-SA\left(t-1\right)}{SA\left(t-1\right)} \tag{90}$$

$$SR\left(t\right)=SR_{NG,RG}\left(t\right)-SR_{RG,NG}\left(t\right)+SR_{SA}\left(t\right) \tag{91}$$

The second alternative is based on the concept of "elasticity of substitution (EoS)" which represents "a proportionate change in the ratio of two factors corresponding to a proportionate change in their marginal rate of substitution or in their price ratio" (Mundlak, 1968, p.1). The substitution rate resulting from this definition is formulated as in Equation 92, where e_{sub} is the parameter representing

EoS and u is a simple additive utility function shown in Equation 93 with weights w_p and w_{SA} given to the relative price and societal acceptance, respectively. Appendix 5 explains how Equation 92 is derived from the definition of EoS.

$$SR(t) = \frac{D_{NG}(t)\,D_{RG}(t)}{D_{NG}(t) + D_{RG}(t)} e_{sub} \frac{u(t) - u(t-1)}{u(t-1)} \tag{92}$$

$$u(t) = w_p \frac{p_{bmt}(t)}{p_{NG}(t)} + w_{SA}\, SA(t) \tag{93}$$

4 MARKET

The wholesale market is the fourth major component of the system model, where gas is purchased from producers and sold to utility companies or large consumers by traders. In addition to balancing the supply and demand via the dynamics of price, the market is where the competition between the supply options takes place. Namely, an increase in the supply quantity or a decrease in the costs of any of the options causes the market price to converge to the price of this supply option, e.g. as a reduction, and this implies a reduced supply by other options which cannot compete with low prices.

Currently in the Netherlands, there is no actual common market for natural and renewable gas, although domestically produced and imported natural gas are traded on the same market. However, since the prices of both are expected to influence each other, a common market mechanism is supposed, and the competition is modeled accordingly.

The market model includes the roles of traders, producers and consumers in price setting as in many energy system models. These models, usually optimization models, assume one of these market players to be the price-setter (e.g. producers), the other to be the price-taker (e.g. consumers), and determine an optimal price based on the objective function. In this model, none of the actors is assumed to be the price-setter. Instead, the influence of each of them is included in the model. Still, different assumptions can be made about the extent of each actor's influence, and different model structures can be developed. This structural uncertainty led to three alternative price-setting mechanisms to be incorporated into the model, representing different forms of involvement of each actor in the market. Technically speaking, a switch structure is used to represent these different price-setting mechanisms as in Equation 94, where *PSS* stands for *Price Structure Switch.* The paragraphs below explain these three structures.

$$p_{market}(t) = \begin{cases} p_{1,market}(t), & PSS = 0 \\ p_{2,market}(t), & PSS = 0.5 \\ p_{3,market}(t), & PSS = 1 \end{cases} \tag{94}$$

4.1.1 Option 1: Sterman's commodity market price setting

This option is based on the price-setting mechanism of the generic commodity market model of Sterman (2000, p. 813). In this alternative structure depicted in Figure 21, three groups of market actors are represented equally, and the *Market Price* of gas (p_{market}) is assumed to be dependent on the *Traders' Expected Price* (*TEP*), producers' desired price represented by the *Effect of Costs on Price (EC)*, and consumers' demand coverage represented by the *Effect of Demand Coverage on Price (EDC)*, as shown in Equation 95.

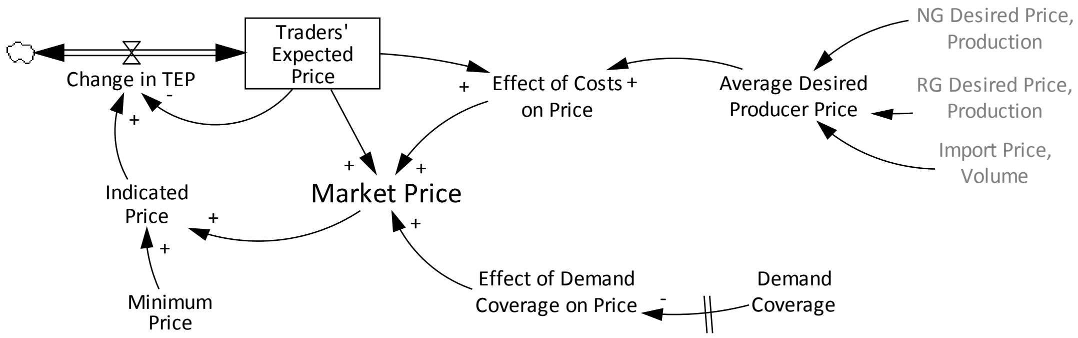


Figure 21: Overview of the first price-setting option

$$p_{1,market}(t) = TEP(t) * EC(t) * EDC(t) \tag{95}$$

Traders' Expected Price is formulated as a stock variable since it is constantly adjusted to the market price with a first order information delay. Traders adapt their expectations continuously having the *Indicated Price (InP)* as a reference, as in the form of a first order information delay. This *Indicated Price* value is assumed to be the maximum of the current market price and a *Minimum Price* (p_{min}) as in Equation 96, which is equal to an average of the 'variable' cost of each supply option, based on the assumption that producers would ask at least their variable cost.

$$InP(t) = \max\left(p_{market}(t),\ p_{min}(t)\right) \tag{96}$$

As for the *Effect of Costs on Price,* it is formulated as in Equation 97 following Sterman (2000). In this equation, k_c is a key parameter representing the *Sensitivity of Price to Costs*. The implicit assumption in this equation is that the market price converges to the desired price of producers if demand coverage has no effect, since the equal value of *DPP* and *TEP* make this function's value equal to 1 when the price is fully sensitive to the costs ($k_c=1$). *DPP* is the *Average Desired Price of Producers*, which is assumed to be a weighted average of the price values (*DP*) expected by each producer group. The weights in this formulation shown in Equation 98 are the market share of each option, i.e. the ratio of its *Production Rate (PR)* or *Import Volume (IV)* to the total supply in the market. This formulation ensures that if one of the supply options is dominant, the market price is closer to its cost value.

$$EC(t) = 1 + k_C\left(\frac{DPP(t)}{TEP(t)} - 1\right) \tag{97}$$

$$DPP(t) = \frac{PR_{NG}(t) * DP_{NG}(t) + PR_{RG}(t)\, DP_{RG}(t) + IV(t) * p_{imp}(t)}{PR_{NG}(t) + PR_{RG}(t) + IV(t)} \tag{98}$$

Lastly, the *Effect of Demand Coverage on Price (EDC)* is also formulated as in the Commodity Market Model, depending on *Demand Coverage* with a negative exponent as shown in Equation 99. This negative exponent, k_{DC} represents the *Sensitivity of Price to Demand Coverage*, and the base of it is the ratio of *Perceived Demand Coverage (PDC)* to the *Reference Demand Coverage (RDC)*, which is the initial demand coverage value in 2012. *Perceived Demand Coverage* takes the delay in the perception of consumers about whether their demand is met or not into account, and formulated with a first order information delay. The actual *Demand Coverage (DC)* is the ratio of total supply in the Dutch market (Equation 1) to the total gas demand of the Dutch consumers (Equation 70), as seen in Equation 100.

$$EDC(t) = \left(\frac{PDC(t)}{RDC}\right)^{-k_{DC}} \tag{99}$$

$$DC(t) = \frac{TS(t)}{TD(t)} \tag{100}$$

4.1.2 Option 2: Price setting based on producer price and demand coverage

The second alternative price setting mechanism excludes the influence of traders, and formulates the market price depending only on the desired price of producers and the effect of demand coverage. This formulation shown in Equation 101 also omits the 'sensitivity' factor used in the previous alternative, and in a simpler way, sets the market price to the multiplication of *Average Desired Price of Producers (DPP)* and *Effect of Demand Coverage on Price*, where the latter is formulated with a graphical function in this case. The input of this graphical function is *Perceived Demand Coverage*, and its form can be seen in Figure 22.

$$p_{2,market}(t) = DPP(t) * f_{dem,price}(PDC(t)) \tag{101}$$

4.1.3 Option 3: Price setting based on accepted consumer price

The third alternative model structure for the market price-setting includes all three actors again, yet with a different role of each. This alternative is also based on a structure found in the system dynamics literature (Barlas *et al.*, 2007) and highlights the role of traders since the profit margin on the costs is assumed to be dependent on acceptance by traders. Different from the original model structure which assumes a constant accepted margin, in this model, the accepted profit margin is assumed to be a variable depending on price. Besides, the role of consumers, i.e. *Effect of Demand Coverage on Price*, is represented by the same formulation as in Option 2.

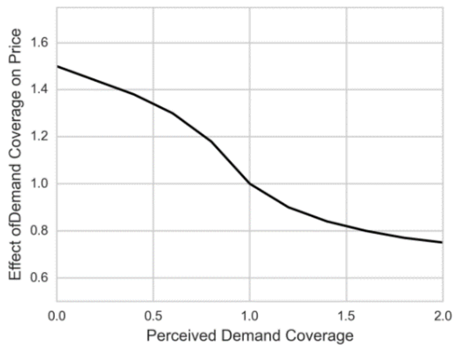


Figure 22: Graphical function showing the *Effect of Demand Coverage on Price*

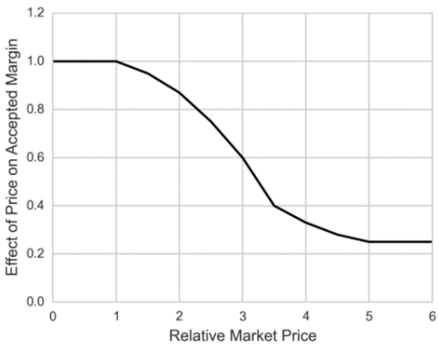


Figure 23: Graphical function showing the *Effect of Price on Accepted Margin*

More precisely, the *Market Price* of gas is modeled with a first order information delay mechanism shown in Equation 102, where the delay time is *Market Price Adjustment Time (d_{market})* and the actual price value is *Traders' Expected Price (TEP^3)*. *TEP^3* is the multiplication of the *Effect of Demand Coverage* and the *Accepted Price (AP)* as shown in Equation 103. As for the *Accepted Price* presented in Equation 104, it is the multiplication of *Average Cost of Gas* in the market (*ACG*), which is the weighted average of total unit costs of the supply options instead of the desired prices of producers, and *Traders' Accepted Margin (TAM)*. This margin has a multiplicative formula seen in Equation 105, where a reference profit margin (*TAM^**) is multiplied by the E*ffect of Relative Price on Accepted Margin ($f_{price,margin}$)*. This effect is represented by a decreasing graphical function (since high prices make traders reluctant to pay more), as well, which can be seen in Figure 23.

$$p_{3,market}(t) = p_{market}(0) + \int_{t_0}^{t} \left(\frac{TEP^3(\tau) - p^3_{market}(\tau)}{d_{market}} \right) d\tau \tag{102}$$

$$TEP^3(t) = AP(t) * f_{dem,price}(PDC(t)) \quad (103)$$

$$AP(t) = ACG(t) * TAM(t) \quad (104)$$

$$TAM(t) = TAM^* * f_{price,margin}\left(p^3_{market}(t) / p_{market}(0)\right) \quad (105)$$

The market price determined with any of these three options affects the profitability in the subsystems of supply options. As for the demand changes, they are determined with respect to the consumer price, which is calculated based on the market price, with the addition of transportation costs and taxes. Equation 106 shows this consumer price formulation, with the main components of an energy bill in the Netherlands being the *Transport Cost (C_{tr})*, *Energy Levy (C_{levy})* and *Value-added Tax* (C_{VAT}). Among these three components, the first two are set as absolute values, whereas VAT is collected as a percentage-based tax. Since the consumer price is different for each sector, an average value of these different prices, i.e. the weighted average based on the demand of each sector, is used as an indicator of consumer prices in testing the effectiveness of policies.

$$p_{consumer}(t) = \left(p_{market}(t) + C_{tr} + C_{levy}\right) * (1 + C_{VAT}) \quad (106)$$

5 CONCLUSIONS

This document presented the simulation model developed in this study to quantify the conceptual system model and to generate scenarios for policies to be tested on. The three segments of the model, namely the supply options, demand sectors and the market, are explained with their main assumptions and detailed formulations. Focusing on the representation of uncertainties, this model included several parametric and structural uncertainties, i.e. multiple alternatives of a model structure if it is subject to uncertainty due to several possible modelling assumptions.

This model is the result of an iterative modelling process. Some steps of this process involved extensions to the breadth and depth of the model to improve its validity, while some of them made simplifications to obtain a ‘good enough’ but a ‘small and simple’ model. Despite such efforts, the eventual model cannot be claimed to be small and simple, but it is considered good enough to capture the complexity of the problem, which itself covers a broad area in the energy sector. Besides the extent of the problem, the aim to use some components of the model in separate studies is the second factor that caused a growth in size. As referred throughout the report, especially the natural gas and renewable gas components of the model are used in studies that focus on the production dynamics of these two types of gas particularly.

The efforts to find simple model structures that can represent uncertainties sufficiently and be used for scenario generation resulted in some formulations which are not fully compatible with the fundamental concepts of system dynamics. For instance, the formulations borrowed from econometrics such as price elasticities of demand or supply-demand curves to derive the changes in import prices would not be found in system dynamics models that aim to describe the actual mechanisms in the system independent from the economic theories. As mentioned, these were conscious choices to have simple structures that can encompass the related uncertainties. Standing as an example of how the features of other modeling methodologies can be utilized to fit model to its purpose, this issue also stresses the question of what features should an exploratory system dynamics model should have.

This model included several actions made by the main actors in the system, such as the investment decisions of natural gas producers or price influence of traders. The structural uncertainties included in the model were mostly related to these decision making mechanisms, resulting from ambiguities due to multiple possible approaches adopted by the actors in the same group. This heterogeneity in the actions of actors, as opposed to the homogeneity assumption in this model, can be accommodated in an agent-based model more thoroughly if the purpose is to investigate the effects of such differences of actors on future dynamics of the system.

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Appendices

APPENDIX 1: EXPLORATION AND DEVELOPMENT COST OF UNIT NATURAL GAS PRODUCED

The exploration and development costs of one unit gas extracted immediately from the *Developed Reserves* are not equal to the unit costs of exploration and development *(C_{exp} and C_{dev})* because of the delays between exploration and production. The effect of these delays is modeled with a co-flow structure and the average exploration cost and average development cost of one unit of developed reserves *(*$C_{exp,DRv}$ and $C_{dev,DRv}$, respectively*)* to be added to the total cost of one unit of gas sold.

Figure A.1 shows this co-flow chain where each stock variable represents the total exploration cost of resources or reserves in the corresponding stock variable. For instance, *Total Exploration Cost of Contingent Resources* accumulate over time as the new resources are discovered at a cost value equal to *Unit Exploration Cost*, and the economically recoverable resources leave this stock at a cost equal to the *Average Exploration Cost of Contingent Resources.* (Note that the flow formulations are multiplications of the cost and resource flow.) This average cost is simply the division of *Total Exploration Cost of Contingent Resources* by *Contingent Resources*. This structure is repeated for each element of the chain, resulting in the *Average Exploration Cost of Developed Reserves*, which is the average cost paid for the exploration of one unit of gas extracted at that time.

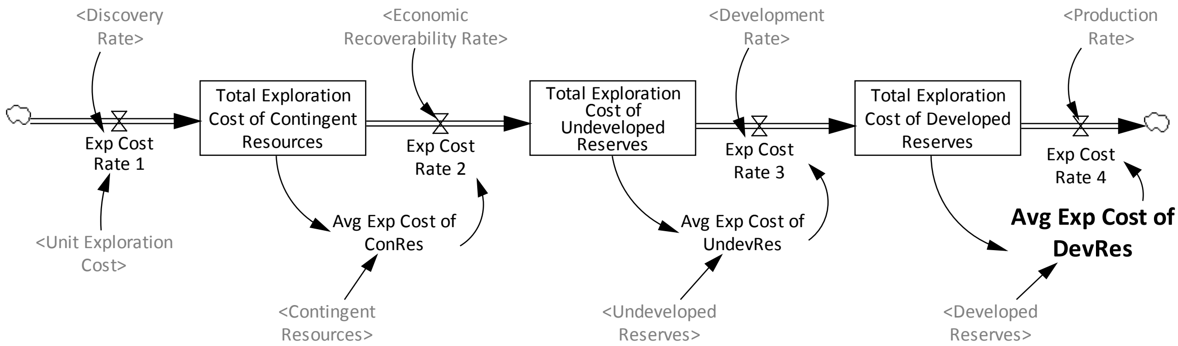

Figure A.1: Co-flow structure for the average exploration cost

This co-flow structure is simpler for the *Average Development Cost of Developed Reserves* since *Developed Reserves* is the only stock variable that causes a delay after development. Figure A.2 shows this structure, where the formulations are the same as those explained in the previous paragraph.

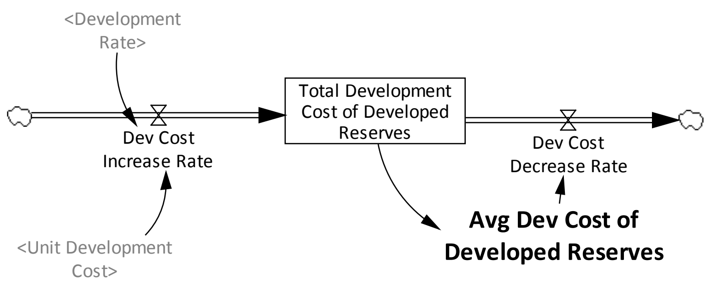

Figure A.2: Co-flow structure for the average development cost

APPENDIX 2: NET COST OF BIOMETHANE PRODUCTION (NC_I)

This formulation replicates the cost calculations of ECN. As in the main text, *i* denotes the number of years ahead, and *r* is the interest rate. The annual equivalent of the investment cost (EAC_{bm}) and the variable unit cost of biomethane (VUC_{bm}) are formulated similar to those of biogas, as in Equations 40 and 39, respectively. (In Equation 40, the term after IC_{bg} gives the annual equivalent of the investment cost.) *Participation Tax* is the income tax, and equal to 25%.

$$NC_i(t) = Annual\,O\,\&\,M\,Costs_i(t) - Tax\,Amount_i(t) + EAC_{bm}$$

$$Annual\,O\,\&\,M\,Costs_i(t) = Inflator_i * VUC_{bm}(t)$$

$$Inflator_i = (1+0.02)^{i-1}$$

$$Tax\,Amount_i(t) = -\%ParticipationTax * \begin{pmatrix} -Annual\,O\,\&\,M\,Costs_i(t) + Annual\,Interest_i(t) \\ +Depreciation \end{pmatrix}$$

$$Depreciation = -\frac{Investment\,Cost}{T}$$

$$Annual\,Interest_i(t) = -r^* * Investment\,Cost * \left(1+r^*\right)^{i-1} - EAC_{bm} * \left(1+r^*\right)^{i-1}$$

APPENDIX 3: IMPORT PRICE

The formulation of *Import Price* is given in Equation A.1. In this equation, $p_{imp}(0)$ stands for *Reference Import Price*, *RI* for *Reference Imports*, and δ for *Import Demand Curve Constant*. This formulation is based on analysing the geometry of the supply and demand curves. The supply and demand curves are assumed to be linear for simplicity, and intersect each other initially at the point (p_1, q_1) as shown in Figure A.3 below. Besides, this formulation implies that the price response to demand change is dependent on parameters like reference import amount, reference price and demand curve constant, which define the demand curve. Since the response of price to demand change is actually uncertain, varying these parameters would allow investigating different price responses.

$$p_{imp}(t) = \frac{p_{imp}(0)}{\delta}\left(CID(t)\frac{\delta - p_{imp}(0)}{RI} + \delta \right) \tag{A.1}$$

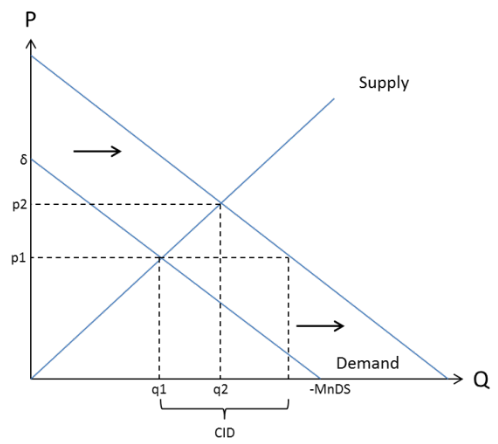

Figure A.3: Geometric representation of the Import Price change with supply and demand curves

An increase in the import demand as the domestic production decreases causes the demand curve to shift upwards, the new equilibrium occurs at (p_2, q_2). p_2 is the price value sought for, which gives the formula of $p_{imp,j}$. (j=pipeline, LNG)

The equation of the supply curve that passes through (p_1, q_1) can be written as

$$p = \frac{p_1}{q_1} q$$

The equation of the demand curve is as the following, where m is the slope and δ is the point that it intersects the price (p) axis:

$$\begin{aligned} &p = -mq + \delta \\ &p_1 = -mq_1 + \delta \;\Rightarrow m = \frac{-p_1 + \delta}{q_1} \end{aligned}$$

Since the shifted demand curve has the same slope and passes through the point (p_1, q_1+CID) where CID stands for the Change in Demand, the equation of the new demand curve is (with x representing where this curve intersects with the x axis, which is –MnDS on Figure A.3)

$$\begin{aligned} &p = -mq + x \\ &p_1 = -m(q_1 + CID) + x \\ &-mq_1 + \delta = -mq_1 - mCID + x \\ &\qquad \Rightarrow x = mCID + \delta \\ &\qquad \Rightarrow p = -mq + mCID + \delta \\ &\qquad \Rightarrow p = -\left(\frac{-p_1 + \delta}{q_1}\right) q + \left(\frac{-p_1 + \delta}{q_1}\right) CID + \delta \end{aligned}$$

The intersection of this new demand curve and the supply curve gives the point (p_2, q_2).

$$\begin{aligned} &p = -\left(\frac{-p_1 + \delta}{q_1}\right) q + \left(\frac{-p_1 + \delta}{q_1}\right) CID + \delta = \frac{p_1}{q_1} q \\ &\Rightarrow q_2 \left(\frac{p_1}{q_1} + \frac{-p_1 + \delta}{q_1}\right) = \left(\frac{-p_1 + \delta}{q_1}\right) CID + \delta \\ &q_2 = \frac{\left(\frac{-p_1 + \delta}{q_1}\right) CID + \delta}{\frac{\delta}{q_1}} \\ &p_2 = \frac{p_1}{q_1} q_2 \Rightarrow p_2 = \frac{p_1}{q_1} \left(\left(\frac{-p_1 + \delta}{q_1}\right) CID + \delta \right) \frac{q_1}{\delta} \\ &p_2 = \frac{p_1}{\delta} \left(CID \frac{\delta - p_1}{q_1} + \delta \right) \end{aligned}$$

In the general formula, p_1 is replaced by Reference Import Price ($p_{imp,j}(0)$) and q_1 is replaced by Reference Imports (RI_j). Import Demand Curve Constant (δ_j) is the parameter that shows the point that the demand curve intersects the price axis, namely it is the price when demand is zero.

APPENDIX 4: OWN-PRICE DEPENDENT CHANGE RATE

Price elasticity of demand is defined as "the percentage by which the quantity demanded will change if the price of the item rises by 1%". In general terms, having Q as the demand quantity and P as price, price elasticity of demand is as shown in Equation A.2:

$$e = \frac{\Delta Q / Q}{\Delta P / P} \tag{A.2}$$

$$\Delta Q = Q * e * \frac{\Delta P}{P} \tag{A.3}$$

From this definition, the percentage change in the quantity demanded is derived as the multiplication of the elasticity and the percentage change in price, assuming a constant elasticity value. Hence, the actual change in demand becomes the multiplication of the quantity demanded, elasticity parameter and the percentage change in price, as Equation A.3 shows. Equation A.4 denotes the use of this formulation for *Own-price Dependent Change Rate (ODCR)* of renewable gas demand in particular. In this equation, D_{RG} is the *Renewable Gas Demand*, e_{RG} is the own-price elasticity of the renewable gas demand, and $p_{bmt}(t)$ is the biomethane price at time t. Since *ODCR* represents the annual change rate in demand, the change in price is determined on an annual basis, too. Hence, the percentage change in price is calculated as the ratio of the difference between two subsequent years to the previous year's price value.

$$ODCR_{RG}(t) = D_{RG}(t) e_{RG} \frac{p_{bmt}(t) - p_{bmt}(t-1)}{p_{bmt}(t-1)} \tag{A.4}$$

APPENDIX 5: SUBSTITUTION RATE BASED ON *ELASTICITY OF SUBSTITUTION*

Elasticity of Substitution (EoS) is defined as "a proportionate change in the ratio of two factors corresponding to a proportionate change in their marginal rate of substitution or in their price ratio" (Mundlak, 1968, 1). Equation A.5 denotes this definition, where Q_1 and Q_2 are the quantity demanded for good 1 and 2, and U_1 and U_2 are the values of the factor they are dependent on, e.g. utility.

$$e_{sub} = \frac{\dfrac{\Delta(Q_2/Q_1)}{Q_2/Q_1}}{\dfrac{\Delta(U_2/U_1)}{U_2/U_1}} \tag{A.5}$$

Following this definition, and assuming a constant elasticity, the percentage change in the demand ratios of natural gas (NG) and renewable gas (RG) at each time step of the model (dt) is

$$\frac{\dfrac{d(D_{NG}/D_{RG})}{D_{NG}/D_{RG}}}{dt} = e_{sub} \frac{\dfrac{d(U_{NG}/U_{RG})}{U_{NG}/U_{RG}}}{dt} \tag{A.6}$$

Denoting the right-hand-side of this equation by Y for now, and knowing that in the case of substitution $\frac{dD_{NG}}{dt} = -\frac{dD_{RG}}{dt}$, the (indicated) substitution rate $\frac{dD_{NG}}{dt}$ can be found as follows:

$$
\begin{aligned}
&\frac{\frac{d\left(D_{NG}/D_{RG}\right)}{D_{NG}/D_{RG}}}{dt} = Y \quad \Rightarrow \frac{d\left(D_{NG}/D_{RG}\right)}{dt} = \frac{D_{NG}}{D_{RG}} Y \\
&(quotient\ rule) \quad \Rightarrow \frac{\frac{dD_{NG}}{dt} D_{RG} - \frac{dD_{RG}}{dt} D_{NG}}{D_{RG}^2} = \frac{D_{NG}}{D_{RG}} Y \\
&\left(\frac{dD_{RG}}{dt} = -\frac{dD_{NG}}{dt}\right) \Rightarrow \frac{dD_{NG}}{dt}\left(D_{NG} + D_{RG}\right) = D_{RG}^{\cancel{2}} \frac{D_{NG}}{\cancel{D_{RG}}} Y \\
&\Rightarrow \frac{dD_{NG}}{dt} = \frac{D_{NG}\, D_{RG}}{D_{NG} + D_{RG}} Y
\end{aligned}
\tag{A.7}
$$

The term with utilities in *Y* represents the percentage change in the relative utility of *NG* to *RG*. In the model, instead of defining two variables, one for NG and one for RG, and looking at their ratios, the relative utility, *u(t)*, is defined as a single variable, i.e. with the ratios of prices and societal acceptance levels of the two gas types (see Equation 93). Therefore, having the percentage change in the relative utility as in Equation A.8, *Y* is re-written as in Equation A.9, which leads to the *Substitution Rate* formulation in Equation A.10.

$$
\frac{\frac{d\left(U_{NG}/U_{RG}\right)}{U_{NG}/U_{RG}}}{dt} = \frac{u(t) - u(t-1)}{u(t-1)} \tag{A.8}
$$

$$
Y = e_{sub} \frac{u(t) - u(t-1)}{u(t-1)} \tag{A.9}
$$

$$
SR(t) = \frac{D_{NG}(t)\, D_{RG}(t)}{D_{NG}(t) + D_{RG}(t)} e_{sub} \frac{u(t) - u(t-1)}{u(t-1)} \tag{A.10}
$$