A comparison of cost-benefit analysis of biomass and natural gas CHP projects in Denmark and the Netherlands

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Abstract

We investigate what drives differences in the project appraisal of biomass and natural gas combined heat and power (CHP) projects in two countries with very similar energy profiles. This is of importance as the European Commission is assessing the potential scope of harmonizing renewable electricity support schemes post 2020. Concurrently, it is also promoting the use of cost benefit analysis (CBA) for transnational energy infrastructure projects. We use CBA to assess the same project proposal in Denmark and the Netherlands, following the respective country's guidelines. We find that especially the fuel costs and the valuation of emissions drive the differences. Furthermore, we establish that the sensitivity of the CBA results not only from policy differences in the countries, but also from differences in the methodology used.

Keywords:

Cost-benefit analysis; combined heat and power; net present value.

1 Introduction

Full harmonization of common, binding provisions for the support of renewably sourced electricity is a long-term aspiration for the EU Commission (EC), where full harmonization extends across the level of support, the support schemes and the legal framework including regulatory issues [1]. Arguably, full harmonization of support schemes will ensure that sites with natural comparative advantages in terms of renewable energy source availability will be developed until any financial advantage gained using the support schemes has been exhausted. Externalities relating to energy generation and the valuation perspective of consumers are usually being investigated with willingness to pay studies. As to renewable energy generation, examples of this type of studies are [2-5]. However, governments are not always inclined to rely on these solutions and they may also have other motives to advance renewable energy generation and consumption.

If we assume that government support is required due to inherent market failures in the energy markets, notably environmental pollution, resource exhaustion and the emission of greenhouse gases, then this support should in some way relate to the size of these market externalities not already accounted for. One way to determine the value of such externalities is to perform a cost benefit analysis (CBA) on a given energy project to estimate what monetary and non-monetary costs and benefits are generated outside the direct transaction between the supplier and the buyer [6, 7]. CBA is an analysis of benefits and costs of a project, including an account of foregone alternatives and the current situation. The methodology aims to find out whether benefits of a project or policy actually outweigh its costs, and by how much in relation to the alternatives (among which usual a ‘do nothing’ option) [7].

CBA is commonly used in public projects, with some member states providing manuals such as the "*Green Book*" in the UK [8], the "*Vejledning for Samfundsøkonomiske analyser på energi-området*" (in English: Guidance for socio-economic analysis in the field of energy) in Denmark [9], and on the EU level [10]. The advantage of such an officially sanctioned manual for public projects is that it sets out clear steps for performing an investment analysis appropriately weighted by socioeconomic factors, such as environmental externalities, valuation of non-traded resources such as land, and regional wage distortions.

At present, CBA guidelines for electricity infrastructure, gas infrastructure and smart grids are being refined by the EC in order to address trans-European energy infrastructure projects [11]. Existing literature on the use of CBA to assess welfare impacts in an international context is found primarily in the general social studies [12]. According to this literature, divergent CBA practices may give rise to indirect barriers to trade and a reduction of economic efficiency.

Disparities in CBA methodologies from state to state are already recognized by the EC, which explains the need of having common guidelines for transnational projects. The purpose of our paper is to demonstrate the extent and determinants of any disparities between two EU member states, the Netherlands and Denmark, by applying their respective CBA methods to the same case study. The two countries are selected on the basis of their similarities in their energy profile. The share of renewable energy is predominantly sourced from biomass and waste for both Denmark and the Netherlands, with wind being the other main contributor. Both countries have significantly higher shares of CHP generation than the EU-28 as a whole, and both countries are net exporters of natural gas. With these similarities in mind, this paper compares a biomass CHP system with a natural gas CHP system. By using the same case study in the two countries, we hope to detect whether any differences in the CBA are a result of either natural variance between the two countries or of discrepancies in the CBA method itself. We want to point out that stated preference methods can be used to quantify in monetary terms the externalities from biomass technologies [13, 14], but these figures are not considered in our analysis since the current policy framework does not rely on this type of analysis.

Section 2 presents the materials and methods employed in the CBA for Denmark and the Netherlands. Section 3 contains the results for each country and a comparison of the two, as well as the impact of a sensitivity analysis on the results. Section 4 discusses factors influencing the results and concludes with policy implications.

2 Materials and methods

2.1 Background of the case study

The EC is keen to promote CBA to guide investment in transnational energy projects [12] and determined to find out whether harmonization of renewable electricity policies at the central EU level would be more efficient than letting it be set at the EU member state level. Assuming that support policies are related to an ex post estimation of net benefits and to correct market externalities, it makes sense to use CBA to determine whether disparities in CBA methodology might threaten potential gains from harmonizing energy policy across EU member states.

A key criticism regarding determining support schemes at a central EU level is that each member state has different geographical, legal, political and market conditions which influence the optimal level of renewably sourced electricity. Studies [15, 16] show that institutional factors may impact development and environmental quality of a country. Ideally, a common framework would result in overall cost savings with favourable conditions for sites with comparative advantages, e.g. wind farms in areas with relatively high average annual wind speed, but it might also result in unacceptable high rents being earned at the most advantageous sites.

Any such differences in conditions between countries might be reflected in the socioeconomic values for economic externalities – positive and negative – set for the CBA of public projects. Presumably, the more similar the geographical, legal, political and market conditions between two countries, the more similar the socioeconomic weights attached to the externalities. As such, this is at the basis of our investigation. The main hypothesis to be tested in this study is that we expect similar results for CBAs of the same project located in two EU member states with highly identical preferences.

In our analysis, regional differences in land costs, electricity prices etc. are ignored in favour of using national averages in order to provide more comparable results. Natural variations between states in, for instance, electricity prices are assumed to reflect national priorities and comparative advantages. It is interesting to determine whether any differences are motivated by natural variations in price levels and energy costs or whether they are driven by other factors such as monetary estimates of greenhouse gas emissions. If these differences result from natural variations in the price level, the path towards full harmonization is much more straightforward. However, if the differences are mainly driven by differences in valuation methodology, then a key requirement is that member states harmonize their public policy valuation guidelines.

We compare projects in two highly similar countries. The energy profiles of Denmark and the Netherlands share a number of common characteristics, such as substantial natural gas fields and an abundance of biomass and wind resources. Both countries have negligible shares of geothermal and hydro energy sources and solar energy is a minor contributor, with only 1%

share in the renewable energy primary production [17]. In contrast, for the EU-28 as a whole, geothermal and hydro energy represent 4% and 16%, respectively, and photovoltaic energy an additional 4% [17]. Primary renewable energy production in Denmark and the Netherlands is instead dominated by relatively large shares of biomass (including waste) and wind power. A second similarity in the energy profiles of the two countries is the high share of combined heat and power (CHP) generation, measured as a percentage of gross electricity generation. For Denmark the average share for 2011 was 46%, with corresponding values for the Netherlands and the EU-28 at 33% and 11% respectively. The shares for CHP generation in the Netherlands and Denmark are substantially higher than in the EU as a whole, with only Latvia, Lithuania and Finland showing similar CHP prevalence [18].

A final similarity relevant for this paper is the natural gas energy profile for the two countries [19]. Relative to primary natural gas production in 2011, the share of imports was 5% for Denmark and 29% for the Netherlands, compared with 251% for the EU-28 as a whole. Gross inland consumption was 59% of primary production for both countries, while it was 284% for the EU-28. Both countries are net exporters of natural gas, and consumption does not exceed production in either country, unlike the EU-28 as a whole [19].

2.2 CBA analysis

Cost-benefit analysis (CBA) is an approach that is used for estimating the strengths and weaknesses of several project alternatives [6, 7]. These alternatives usually have to satisfy transactions, activities or functional requirements for a business. CBA can also be used to calculate and compare the costs and benefits of public project or of projects with a mixed public-private nature. In general, the aim of CBA is to compare projects along their net present value.

CBA is an instrument that has been applied to assess options regarding the choice among alternatives and practices in terms of financial benefits, and savings in terms of labor, time and resources [7]. Often, CBA is used to find out if a particular project is a sound investment and whether the decision to go ahead with a project can be justified in terms of costs and resources. It also can be used as a feasibility study. Furthermore, CBA is used as a means to compare alternative, competing projects. As such, it aims at arriving at a comparison of the expected costs and benefits of alternative projects. Costs and benefits usually are expressed in financial terms and are adjusted for the time value of money [6]. This is not always possible and stakeholders will not always agree about the categories of costs and benefits that have to be accounted for and how to arrive at monetary values for all the categories.

Table 1 gives an overview of the assumptions used in the analysis. Please note that all prices are reported in real prices at the 2011 price level. We report costs and benefits and values in Euros. In this respect, for the Danish Krone (DKK) we use an exchange rate of DKK 7.5 per Euro [26]. Another issue is that the physical size of our project, that is the CHP system being investigated, is small. As such, the project is not automatically included in the EU Emissions Trading System (ETS), which would make it eligible for additional carbon costs.

Table 1:

Key assumption of the CBA analysis

	Denmark	The Netherlands
Discount rate	4%	
Time horizon (years) – *a*	15	
Heat capacity biomass CHP unit (kW) – *a*	420	
Heat capacity natural gas CHP unit (kW) – *a*	360	
Electrical capacity biomass CHP unit (kW) – *a*	105	
Electrical capacity natural gas CHP unit (kW) – *a*	300	
Total cost of biomass CHP unit, installed (in euros, including buildings) – *a*	707,500	
Total cost of natural gas engine CHP unit, installed (in euros, excluding buildings) – *a*	450,000	
Total cost of natural gas turbine CHP unit, installed (in euros, excluding buildings) – *a*	630,000	
Utilization rate natural gas unit – *a*	95%	
Utilization rate biomass gas unit – *a*	87%	
Volume of gasified biomass per hour of full load combustion (in Nm3) – *b*	407.6	
CO2 emission intensity of natural gas (in kg/GJ) – *c*	56.7	56.6
Energy content of the natural gas (in MJ/Nm3) – *c*	39.51	31.65
Projected CO2 quota values 2014 (in euros/ton) – *d*	12.07	5.97
Projected CO2 quota values 2020 (in euros/ton) – *d*	25.31	9.07
Projected CO2 quota values 2025 (in euros/ton) – *d*	29.53	12.83
Projected CO2 quota values 2029 (in euros/ton) – *d*	32.90	15.83
Emission values SO2 (in euros /kg) – *e*	12.62	5.24 (L) / 10.49 (H)
Emission values NOx (in euros /kg) – *e*	6.54	5.24 (L) / 10.49 (H)
Emission values PM2.5/10 (in euros/kg) – *e*	14.90	2.41 (L) / 52.44 (H)

a [20]

b [21]

c [22] for Denmark, [23] for the Netherlands

d [22] for Denmark, [24] for the Netherlands

e [22] for Denmark, [25] for the Netherlands; L = low, H = high

As to the discount rate, the Danish Ministry of Finance recommends that a 4% interest rate is used for analyses conducted in the time horizon 0-35 years, dropping to 3% for years 36-70 and 2% for the years following [27]. The Dutch Ministry of Finance recommends a discount rate of 5.5% or 4% for public investments, consisting of a risk-free rate of 2.5%, with a risk premium of

3% in the general case or a risk premium of 1.5% when valuing specific negative externalities which are irreversible [28]. These rates were most recently used in a CBA of 6,000 MW onshore wind developments by the Dutch Central Planning Bureau (CPB) [29], where the 5.5% rate was used for the general analysis and the 4% rate was used to value emissions with a negative impact on the environment.

The recommended social discount rate from the European Commission's *Guide to cost benefit analysis of investment projects* [10] is 3.5% for mature economies within the EU, and is partially derived from per capita growth rates. Particularly for renewable energy investments, where the benefits accrue over a long lifetime while the costs are mainly upfront, a lower discount rate may have a significant impact. That both Denmark and the Netherlands use higher discount rates (4% for the long term [27, 28]) than recommended by the EU (3.5% [10]) hints at an undervaluation of long-term externalities in these two countries.

The time horizon used in the analysis is based on the expected technical lifetime of the biomass-based CHP solution used in the reference scenario, set at 15 years [20]. Assuming a contract is signed in the beginning of January 2014 and a six month delivery and installation time, the plant will run from mid-2014 to mid-2029.

The choice of baseline is very important in CBA. The reference scenario consists of a small-scale woodchip powered combined heat and power system (CHP), while two alternative scenarios are considered. The first is an electric spark ignition engine and the second is a mini single cycle gas turbine, both of which run on natural gas and are CHP systems. The technical data is taken from *Technology Data for Energy Plants*, published by the Danish Energy Agency [20].

Please note that the technical lifetimes of the three technologies actually differ. While the biomass-based CHP system has a technical lifetime of 15 years, the mini single cycle gas turbine has an expected lifetime of 10 years, and the electric spark ignition engine has a lifetime of 20-25 years. For the mini single cycle gas turbine, there should be a capital reinvestment in year 11; for the electric spark ignition engine, there should be some residual value of the system after a 15-year operation period. However, the emphasis in this paper is on how the differences in CBA methodology between Denmark and the Netherlands in combination with country characteristics will produce different results; in this case, both countries would follow the same approach (accounting for residual value at the end of the technical lifetime). As a result, the effect would cancel out in a cross-country comparison. For the sake of simplicity, we have therefore assumed a lifetime of 15 years across all three technologies.

The economic agent profiled in the case study is an industrial greenhouse owner who uses process heat to grow vegetables. The average physical size for a greenhouse in Denmark is 4,000 square meters (sqm) and a greenhouse owner will typically have six of these. To grow vegetables requires a temperature of 18 degrees Celsius, roughly equal to 2,800 MWh of heat and 70 MWh of electricity annually. Greenhouse owners use natural gas boilers, natural gas CHP units or a combination of these two to provide energy to the greenhouses [30].

We assume that the natural gas systems can be installed in the existing buildings as a replacement for the system in operation, while in this case study the biomass system must be installed greenfield, i.e. on new land with new buildings. This is partly to account for the much larger area required to house woodchip fuel in contrast to natural gas, which has a much higher energy density. In the Danish case study, it is assumed that a greenhouse owner wishes to test a biomass CHP unit in one of the greenhouses. This is motivated by the Danish greenhouse association HortiAdvice Scandinavia A/S, which works with Danish greenhouse owners to test carbon neutral solutions for 2017, and by the Danish government's offer of tax breaks and subsidies for carbon neutral energy solutions. The Dutch greenhouse industry is roughly thirty times larger than the Danish one when measured by sqm, but an average Dutch vegetable grower has a comparable greenhouse area, capable of fitting up to seven greenhouses on 4,000 sqm. Much like the Danish sector, energy demand is primarily fuelled using natural gas [31]. Given that the sizes and energy profiles are quite similar, we assume that energy consumption for the same types of vegetables is similar as well. In 2008, the Dutch agricultural industry signed a sector-specific agreement with the government to increase energy efficiency by 2% annually and to aim for a renewable energy share of 20% by 2020 [32]. The sector scheme mimics the setup of the EU emissions trading scheme (ETS) without being a formal part of it, in return for investment subsidies and a reduction in energy taxes.

As heat is the primary energy output the greenhouse owner is interested in, all the plants are scaled according to their heat output rather than their electric output. The extra electricity produced by the natural gas CHP system was sold to the grid previously, but with the biomass unit, all electricity produced is used onsite instead. The costs and/or benefits of the change in grid balancing itself is ignored in this paper as the unit capacities are so small that any change in the grid balancing costs from the sale of electricity to the grid will be minor.

The biomass CHP unit will be installed as a greenfield investment, that is, built on a site located near the greenhouse where there are no previous installations. For the sake of simplicity, we ignore the costs of extending the grid infrastructure, but an estimate of the building costs to house the biomass CHP unit is included. This is obtained directly from the manufacturer, Stirling.DK Ltd. (2012), and covers the costs of installing the equipment in a series of standardsized shipping containers, ready to be placed on site. In order to cover the average estimated heat demand of the greenhouse, the owner has decided to invest in a 105kW electric unit, which will provide 420kW heat, enough to cover the estimated average annual heat needs +15% at full load production.

Disposal costs of the systems (existing and new) are assumed to net to zero once the scrap value has been accounted for. Operation and maintenance (O&M) costs are technical costs and constant regardless of whether the unit is located in Denmark or in the Netherlands. These O&M costs are slightly higher per unit of energy generated for the biomass-based system than the two natural gas based systems. Basing annual operation hours on the heat demand, both the natural gas units would operate at 95% of the year at full load, while the biomass unit would operate at 87% [20]. Hence, the corresponding annual O&M costs are 20% lower for the biomass unit than for the natural gas units. We may expect some labour costs on the side of the greenhouse owner, both in the installation phase and the operation phase of the plants, but for our analysis these costs have been excluded. There is a change in land use from switching from the natural gas system to the woodchip system, equal to the land costs necessary for housing the new energy system plus woodchip storage. Land cost estimates for the Dutch case are derived from the direct cost estimates [33], and inflated with respect to the 2011 price level. Land cost estimates from the Danish case are taken from average alternate use estimates in a recent CBA of biogas installations [34].

The biomass unit uses a small amount of natural gas to start up the system, and then switches to woodchips. The gas units only use natural gas. The amount of natural gas used in the biomass unit for a start-up is very small (less than 1% of total fuel use) and is therefore ignored in this analysis [21]. There are no official Dutch statistics on wood fuel prices [35]. Instead, cost projections have been taken from an EU report providing an illustrative case study of woodchips supplied to the Netherlands [36]. These woodchips are provided as factor price estimates including cultivation, harvesting, storage and transportation, but excluding taxes. The prices are modified using a net tax factor of 1.166 [37]. Danish woodchip price projections are provided by the Danish Energy Agency, including socioeconomic estimates of transport and storage costs up to the delivery point. These prices also are provided as factor prices and have subsequently been adjusted using a net tax factor of 1.17 [38].

Natural gas prices for the Netherlands are based on [24], while natural gas prices for Denmark are based on [39]. The Dutch prices were only available for 2010, 2020 and 2030, and strict linear interpolation is used to provide estimates for the other years. The Danish prices are available including estimates of transport and storage costs up to the delivery point. None of the reviewed literature provided similar estimates for the Dutch prices, so these modifications are ignored in the analysis in favour of using comparable values. Gas prices are adjusted with their respective net tax factors, as are the woodchip prices. The prices per cubic meter of natural gas were converted according to national estimates of the energy content of the fuel (see Table 1).

For electricity prices, the Danish price projection is taken from [38]. The Dutch price projection is based on the background data used to evaluate the Dutch energy agreement [24]. Both projections are in factor prices and adjusted with their respective net tax impact factors. Unfortunately, only data for 2014 and 2020 for the Dutch projection were released to the general public, so the remaining data has been derived on the basis of linear interpolation. However, after the net tax impact factors, the values correspond roughly with the price projections used in the recent public CBA analysis of a 6,000MW wind farm [29].

In the reference scenario, the system is fuelled by biomass gasified onsite, which is combusted directly in the CHP unit. No woodgas is upgraded and exported to the biogas grid. Excess electricity is exported to the grid for balancing purposes. With the natural gas units, excess electricity produced is sold to the grid, giving rise to energy income. It is assumed there are no grid integration issues with replacing the existing natural gas unit with a new one.

We include subsidies and taxes in our calculation of the deadweight loss, which estimates the costs to society of financing changes in the tax base [37, 39]. In Denmark the social deadweight loss is calculated by multiplying changes in the tax base by 20% [9]. Noteworthy taxes are the energy tax on natural gas ("*energiafgift*"), the energy savings tax ("*energispareafgift*"), previously the carbon dioxide tax) and taxes on emissions of NOx and SO2. The effects of these taxes are likely to be minor, especially since greenhouse owners are exempt from 98.2% of the energy tax on natural gas [40]. There was no mention of this practice in the Dutch CBAs reviewed, so it is clearly not common practice and is therefore excluded from the Dutch CBA case in our analysis.

In Denmark, industrial energy producers can choose between a subsidy covering upfront investment costs or a feed-in tariff supporting electricity fed into the grid. As this CHP unit produces correspondingly more heat per unit of electricity, all of which is used onsite, we would expect the greenhouse owner to apply for the upfront capital subsidy. The upfront capital subsidy is valid for investment costs exceeding a conventional energy alternative, up to a maximum of 65% of the whole investment cost for small industries or DKK 23 per GJ fossil fuel replaced over a 10-year period [41]. As the difference in costs of the two installations is less than 65% of the total biomass CHP unit, it is expected that the Danish greenhouse owner will get the full difference subsidized.

The relevant subsidy in the Dutch case is the "*Stimulering Duurzame Energieproductie Plus*" (SDE+; in English: Promotion of Sustainable Energy Generation Plus), in this case given per natural cubic meter (Nm3) gasified biomass converted into heat and electricity, for a maximum of 12 years and up to 7,500 hours annually. The base rate is modified per year. A conservative estimate is taken by modifying the applicable Phase 1 value (19,444 €/GJ) by the annual adjustment factor for 2013 (-10.3 €/GJ) and expressing it in 2011 values.

The amount of emissions associated with each generated unit of energy (emission intensity) depends not only on the fuel type but also on technology characteristics of the energy plant used [39]. The technology-specific emission intensities published by the Danish Energy Agency [38] are based on existing plants and therefore do not accurately reflect new plants. The emission intensities of electricity are location-specific, as emissions will reflect the fuel types and generation efficiencies of the energy generation sites. The emission intensity of natural gas should be similar across borders, although this may change if biogas is increasingly mixed with natural gas in the gas pipelines.

The CO2 emission intensity of natural gas is closely linked with its methane content. Methane content may differ from gas field to gas field. Here, the emission intensity of natural gas is roughly the same for the two countries (see Table 1). There is no EU-wide consensus on how to value the social costs of CO2, but there is an EU-wide Emissions Trading System (ETS) with a common platform for the majority of the EU members including Denmark and the Netherlands. From 2013 onwards, emission allowances for power generation are mainly allocated via auctioning, estimated to cover 40% of allowances in the system in 2013 and increasing up to 2020. While neither the Danish nor the Dutch greenhouse owner in this scenario falls under the scope of the ETS [42], the quota prices have been chosen as a proxy for shadow prices. However, the ETS only extends to 2020. Therefore, we will use national assumptions to extend the CO_2 estimates after 2020, although the European Union suggests minimum lower bounds for the projected ETS carbon prices in the Commission reference scenario up to 2050 [1]. The equations used in the calculations are provided in Appendix A.

The Danish Energy Agency follows the CO_2 quota estimates reported by the International Energy Agency (IEA) to value avoided emissions [38]. In the recent CBA of the 6,000 MW onshore wind energy project, the Dutch CPB provided an overview of CO_2 values in the literature [29]. They use estimates of the damage from CO_2 emissions post 2020 to valuate positive externalities from building additional wind turbines in the event that the ETS was not extended further. For our case study, the values from Koelemeijer et al. [24] are used (see Table 1). The CO_2 values differ significantly in magnitude: Danish values being between two and three times the Dutch values. Other greenhouse gas emissions commonly considered alongside CO_2 are N_2O and CH_4 (methane). Following from the 2006/2007 IPCC guidelines, the damage from 1 kg of emitted CH_4 corresponds to the damage from 25 kgs of CO_2 while the damage from 1 kg of N_2O equals 298 kgs of CO_2 [28]. The same figure for CH_4 was obtained from de Bruyn et al. [25], while no corresponding figure for N_2O was obtainable from the Dutch literature reviewed here. However, it is assumed that the Dutch N_2O damage assessment is in line with the IPCC guidelines.

Other emissions associated with energy generation relevant for this case study are SO_2, NO_x and particulate concentrations, $PM_{2.5}$ and PM_{10}. In the Danish guidelines, only $PM_{2.5}$ is valued, whereas both $PM_{2.5}$ and PM_{10} are valued in the Dutch guidelines [42]. However, as they are given the same value, they will be considered interchangeable in this paper purely for practical reasons.

The emission intensities of the above greenhouse and non-greenhouse gases, excluding CO2, are technology-dependent so only the values from the technical characteristics in [20] are needed. These are given in Table 2. The values of avoided emissions of SO2, NOx and PM2.5-10 are based on estimated damage costs. For the Netherlands, these are available as a range whereas the Danish values are only given as a point estimate.

Table 2:

Emission intensities of CHP units studied

g/MWh	CH4	N2O	SO2	NOx	PM
Natural gas-fuelled CHP	1,674	2.16	1.08	486	0.58
Woodchip-fuelled CHP	11	2.88	6.84	423	11.16

Values are from [20, 38]

3 Results

Table 3 provides the results of the NPV calculations. We subtract the NPV for the natural gas units from that of the biomass CHP. Hence, a positive result suggests that the biomass project provides greater net benefits than natural gas CHP and the other way round.

Panel A gives the results for the biomass CHP and the electric spark ignition engine that runs on natural gas. For both Denmark and the Netherlands, the NPV is clearly positive, with 66.5 million Euros and 22.7 million Euros for each case, respectively. These are net benefits of the biomass CHP over the natural gas CHP. In both countries one would therefore ignore the natural gas investment in favour of the biomass installation.

A closer look at the net benefit calculations shows that the largest benefit is captured from the reduction in methane emissions from the switch from the natural gas CHP. Methane emissions are weighted heavily in both countries as part of the combined greenhouse gas emissions, with one kg of CH_4 being equal to 25 kgs of CO_2 [43]. Methane emissions from the electric spark ignition engine gas CHP system are particularly high, with about 9.6 tons of methane emitted annually for the system estimated in this paper.

Table 3:
Net present values for the biomass CHP minus the natural gas CHP (in million euros)

	NPV
Panel A – Biomass CHP minus natural gas CHP (spark ignition)	
Denmark	66.5
Netherlands	22.7
Panel B – Biomass CHP minus gas turbine (spark ignition; excluding costs of methane emissions)	
Denmark	-0.8
Netherlands	-1.5
Panel C – Biomass CHP minus gas turbine (single cycle mini gas turbine)	
Denmark	0.2
Netherlands	-1.1

Methane emission costs represent roughly 99% of the total emission costs for both Denmark and the Netherlands. The remaining three categories of deadweight social loss, fuel costs and O&M costs are not noticeable. If the methane emissions are excluded from the analysis, i.e. the other greenhouse gases and all other variables are kept constant, the NPV calculations change to approximately -0.8 million Euros and approximately -1.5 million Euros for Denmark and the

Netherlands, respectively (see Panel B of Table 3). Hence, by excluding methane emissions, the NPV changes from a positive to a negative number, such that the biomass CHP now carries a net cost to society instead of a net benefit.

If instead of a spark ignition engine CHP system the greenhouse owner would choose to invest in a single cycle mini gas turbine CHP system, the difference in annual methane emissions would reduce from 9.6 tons to only 10 kgs. By modifying the rest of the technology-specific assumptions accordingly on the basis of data from the Danish Energy Agency [20], the resulting NPV calculations are given in Table 3, panel C. The use of a different natural gas CHP technology in the natural gas CHP scenario provides more ‘reasonable’ NPVs relative to the initial capital investment cost. For Denmark, the biomass CHP technology still presents a net benefit to society relative to the natural CHP with a positive NPV of approximately 0.2 million Euros. However, the Dutch case now results in a negative NPV, signifying that the biomass CHP confers a net cost to society compared to the alternative natural gas CHP technology.

The difference in the present value of the O&M costs in both countries and the deadweight social loss for both states are marginal. Negative present values are predominantly due to the loss in energy income from the reduced sale of electricity to the grid, while benefits primarily result from the reduced emissions of the gases considered. Fuel costs are counted as a net benefit in Denmark, as annual fuel costs for the wood chip CHP system are lower than for natural gas, while the reverse is true for the Netherlands. The loss in electricity income is comparable for the Netherlands and Denmark. Deadweight social loss has a minor impact in both states and for both alternate natural gas systems in this case study. This is mainly due to the relatively small scale of the proposed projects.

Table 4 shows the NPV of the estimated subsidy for the reference energy plant, the biomass CHP, relative to the NPV estimates of the reference and the two alternative plants, the natural gas based spark ignition engine and single cycle mini gas turbine. There are two subsidy estimates for Denmark, as the subsidy is based on the investment difference between the reference and each of the alternate scenarios. For the Netherlands, the estimated subsidy is based on 12 years of additional income gained based on the Phase 1 value in the SDE+ policy support program.

Table 4:
Cost benefit and subsidy NPVs for Denmark and the Netherlands
(in 2011 euros for base year 2014)

	Denmark[1]		Netherlands[2]	
	Turbine	Engine	Turbine	Engine
NPV subsidy	74,519	247,596	1,273,684	
NPV investment	173,502	66,488,495	-1,098,325	22,742,314

[1]Calculated at a discount rate of 4%

[2]Discount rate of 5.5%.

The Danish subsidy levels are significantly lower than the Dutch ones for the same technology, and they do change in line with the reduction in NPV from one comparison to the other. This is one of the advantages of the capital investment subsidy relative to an annual compensation in the form of a feed-in tariff or premium. The magnitude of the Dutch subsidy does not change regardless of whether the estimated NPV is positive or negative.

Our sensitivity analysis is broken down into six segments, shown in Table 5. Given the dominance of methane emission values for the spark ignition engine CHP system, the sensitivity analysis is conducted using the mini single cycle gas turbine CHP system for the natural gas technology. What we do in the analysis is add or subtract 25% for the five main factors involved.

For example, in our fifth sensitivity analysis, we increase respectively decrease electricity costs with 25% and calculate the impact on the net NPV as reported in Table 3 (Panel C) and in the first line of Table 5. Furthermore, we use another discount rate for the NPV.

The Dutch NPVs are negative throughout all of the sensitivity variations, while the Danish NPVs are balanced equally between negative and positive depending on the direction of change in sensitivity. The NPVs show the most variation to sensitivity analysis of the two fuel prices. This is especially noteworthy given that fuel costs only are the third factor impacting the NPVs, following energy income and emission costs. The use of a the 3.5% discount rate instead of 4% or 5.5% shows to have very little impact on the NPV.

Table 5:
Sensitivity analyses; changes in relation to the original NPV
(in thousands of 2011 euros for base year 2011)

	Denmark[1]		Netherlands[2]	
Original NPV	179		-1,098	
+/- 25% Investment + O&M for biomass CHP	-56	414	-1,328	-869
+/- 25% Woodchip fuel cost	-339	697	-1,705	-491
+/- 25% Natural gas fuel cost	763	-405	-539	-1,658
+/- 25% Greenhouse gas emission cost	481	-123	-989	-1,207
+/- 25% Electricity costs	-110	468	-1,404	-793
NPV at a 3.5% discount rate	193		-1,234	

All values rounded to nearest thousand.

[1]Calculated at a discount rate of 4% unless otherwise indicated.

[2]Discount rate of 5.5% unless otherwise indicated.

4 Conclusion

The aim of this paper was to examine sources of any discrepancies in cost-benefit analysis (CBA) methodology and to estimate how this might impact the results. The purpose of the EC is to harmonize renewable electricity support across EU member states. Assuming the allocation of such support is most efficient when there are net positive externalities not captured by market transactions, then allowing states to have divergent approaches to CBA may counteract the economic gains from the harmonization of policy support.

We study the differences in project appraisal of a biomass project versus two types of natural gas combined heat and power (CHP) projects in Denmark and the Netherlands. These countries were chosen because of the high similarity in their energy profile. We want to find out whether the CBA yields similar results for identical projects located in two EU member states with highly identical preferences. The two countries also have highly similar energy system profiles regarding natural gas and renewable energy. To investigate this issue, we rely on CBA as it is an approach that can be used to estimate the strengths and weaknesses of project alternatives. CBA can also be used to calculate and compare the costs and benefits of public project. In general, the aim of CBA is to compare projects along their net present value. Any differences in the results of our case study would suggest that there is divergence in the methodology or a natural variance between the two countries, or a combination of both. Our results demonstrate that the Danish results from the CBA are significantly more positive than those for the Netherlands. This seems to be due to a combination of differences in the methodology used and in differences between project assessment and policies in the two countries. As such, the hypothesis of similarity has to be rejected. Apart from using CBA, we think it might be worthwhile to use other types of analysis and methods as well when trying to account for externalities, such as stated preference methods.

Methodological differences specifically include the choice of baseline for comparison, the discount rate, treatment of distributional weights and social deadweight loss, among others [10]. The estimation of socioeconomic weights also is to be put under this heading, although it might be equally justified to include it as part of the natural variation between states or even regions. Natural variation includes data consistency and quality for instance for fuel costs, electricity prices, land and labour etc.

In our analysis, much of the disparity between the results in the two countries can be attributed to the difference in fuel costs. More specifically, the Danish woodchip prices are lower than the Dutch, while the reverse is true for differences in the natural gas prices. These differences are pervasive enough that the net fuel costs are included as a benefit in the Danish case, i.e. the switch from natural gas CHP to biomass CHP results in annual fuel cost savings, while net fuel costs in the Netherlands impose an additional cost on the biomass CHP owner. National variations in fuel costs can be seen as a natural difference in the comparative advantages of two EU member states.

Another factor that plays a role is the emission valuations. These are significantly different for both countries, and while some disparity should be expected, the extent of this disparity is so great that it dominates the estimation of net public benefits. Related is that the inclusion or exclusion of the impact of methane on the environment turns out to make a huge difference as to the value and appraisal of the investment projects.

The difference in results is most clear in the choice of baseline for the analysis. For the Danish case, the resulting NPV is positive regardless of whether the woodchip CHP is compared with the engine or turbine alternative. However, in the Netherlands, there is only a positive NPV for the engine alternative. This has at least two implications for policy design. First, if subsidies for renewable electricity are awarded irrespective of what fossil fuel alternative they crowd out, then policymakers run the risk of rewarding projects which promote net social loss. Second, the results are highly sensitive to the choice of baseline technology. For this paper, it was assumed that the choice of natural gas system was simply a replacement for an existing unit, with two alternative technologies included to demonstrate sensitivity. In the real world, the project manager may be choosing from a larger set of possible alternatives. It is possible that the choice of baseline or even multiple baselines may be couched in order to prove the desired NPV outcome. Another limitation of our analysis is not taking into account the potential additional benefits from industry and business growth in new areas, and security of energy supply by diversifying among energy sources. We suggest that further research in the formulation of CBA methodology for a common EC policy framework includes case studies to demonstrate the extent of sensitivity both due from natural variations between states and from discrepancies in the approach used.

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Appendix A

Financial and macroeconomic equations used in the analysis (source [1, 43])

a) Calculation of global costs for financial calculation

Global costs for buildings and building elements are to be calculated by summing the different types of costs and applying a discount factor to express them in terms of value in the starting year, plus the discounted residual value as follows:

$$C_g(\tau) = C_l + \sum_j \left[\sum_{i=1}^{\tau} \left(C_{a,i}(j) \times R_d(i) \right) - V_{f,\tau}(j) \right]$$

where:

τ	means the calculation period
$C_g(\tau)$	means global cost (referred to starting year τ_0) over the calculation period
C_l	means initial investment costs for measure or seat of measures *j*
$C_{a,l}(j)$	means annual cost during year *i* for measure or set of measures *j*
$V_{f,\tau}(j)$	means residual value of measure *j* at the end of calculation period
$R_d(i)$	means discount factor for year *i* based on discount r to be calculated as:

$$R_d(p) = \left(\frac{1}{1+\frac{r}{100}} \right) \quad p$$

where p means the number of years from the starting period and r means the real discount rate.

b) Calculation of global costs for the macroeconomic calculation

When determining the global cost at the macroeconomic level of e measure, package or variant, in addition to the conventional costs categories, a new cost category of greenhouse gas emissions is to be included so that the adjusted global cost methodology reads as:

$$C_g(\tau) = C_l + \sum_j \left[\sum_{i=1}^{\tau} \left(C_{a,i}(j) \times R_d(i) \right) + C_{c,i}(j) - V_{f,\tau}(j) \right]$$

where:

$C_{c,i}(j)$ means carbon cost for measure *j* or set of measures *j* during year *i*.