ESG Economist

Transition check: are renewables in crisis?

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- **The energy transition is an economy wide process where a development in one part affects, directly or indirectly, other parts**
- **Bottlenecks or costs challenges could harm an effective energy transition**
- **The effect of today's bottlenecks on the transition, such as the limited grid capacity, is magnified because of the mismatch in the timeframe for deploying grid extensions versus what is needed for electrification or renewable deployments**
- **The tight labour market for energy transition occupations and the resulting lack of personnel to undertake the necessary work is also an additional bottleneck in the industry**
- **Vulnerability to supply chain disruptions, inflationary pressures, rising financing costs and higher raw material costs are some of the other factors deteriorating the business case for renewables**
- **The government also plays an important role in keeping these investments financially viable: When these do not materialize as expected, such as with the tax credits in the US, this serves as a blow to the industry as a whole**
- **At the same time, governments also need to meet public interests, resulting in auction prices still remaining relatively high (and/or maximum allowed prices low) as they try to push for lower energy prices**
- **These challenges also have potential spill over effects: The impact of limited infrastructural capacity does not only affect the transition domestically, but it could limit the transition across borders**
- **Hence, managing the speed of the transition across different channels is crucial for avoiding unnecessary delays or weakening the incentives to invest in clean technologies**
- **In this piece, we also try to quantify all these challenges and evaluate how they impact renewable energy developer's returns.**
- **Overall, our calculations show that the current macro- and microeconomic environment does not yield sufficient returns in order for these projects to be viable from an investment point of view…**
- **…Ultimately meaning that the renewable energy industry is in crisis**

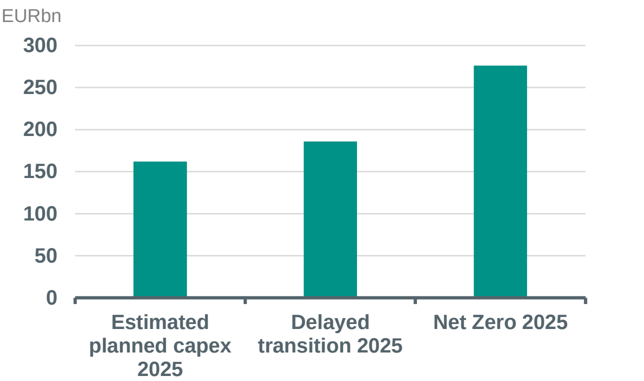
Introduction

A transition is, by definition, a dynamic process that needs time to materialize. However, when it comes to the energy transition, time becomes a key factor given the climate action urgency.

There are, in general, three channels for the energy transition. First, a switch away from fossil fuels towards more renewables for power generation. Second, moving towards alternative clean energy carriers, such as green hydrogen, in sectors where the technology is available and feasible. Third, investing in efficiency improvements for fossil fuel usage in sectors where no clean alternative technology is yet available. Furthermore, such large scale structural transition requires supporting infrastructural investments. For example, extending the electricity grid and repurposing the gas network are needed to accommodate the increase in the power supply and the rising demand from electrification.

The literature around the energy transition emphasizes the need to have the right policies in place to reach the emission reductions and climate goals. However, reality has proven otherwise. Indeed, policies are a crucial factor to deliver incentives to increase investments in clean technologies, but these do not come as expected in the level of ambition and in the speed that is required. Moreover, there are bottlenecks and unexpected shocks, which induce a risk that climate goals are not reached in a timely and orderly manner. Our previous analysis showed that planned investments in the energy transition are still significantly below the one needed to achieve net zero goals by 2025 (see here), and any additional challenges could challenge the much needed energy transition.

Planned energy transition investments are not enough



Source: Bloomberg, NGFS, ABN AMRO Group Economics. Note: planned capex for 2025 takes into account equity analyst consensus figures for 2024, applying a constant growth rate from 2024-2025 based on historical averages, assuming a 15% grant from government subsidies and a EUR 55bn in investments from project finance.

Primary risks associated to key clean technologies

	Wind	Solar PV	Nuclear	Battery storage	Demand response	Grids	Electric vehicles	Heat pumps
Regulatory and policy risks								
Regulatory frameworks	Medium	Low	Medium	Medium	High	Medium	Medium	Medium
Policy support	Low	Low	Medium	Low	High	Low	Low	Low
Permitting and certification	Medium	Medium	High	Low	Low	High	Medium	Low
Supply chain risks								
Critical minerals	High	Medium	Low	High	Low	Medium	High	Low
Manufacturing	High	Low	Medium	Medium	Low	Low	Low	Medium
Skilled labour	Medium	Medium	High	Low	Low	High	Low	Medium
Financial risks								
Costs of financing	High	Medium	High	Medium	Low	High	Medium	Medium
Revenue and savings predictability	Medium	Low	Low	Medium	Medium	Low	Low	Low
Overall risks	High	Low	Medium	Medium	Medium	High	Low	Medium

Source: IEA

Hence, this note highlights different obstacles facing investments in renewables. We focus on potential implications of the combination of policies and bottlenecks. To make things more tangible, we included a case study, where we revisit the financial feasibility of offshore wind projects in light of these bottlenecks. We show that the current situation is posing a great risk towards renewable energy investments. We conclude with recommendations on how to solve these problems.

Transition bottlenecks

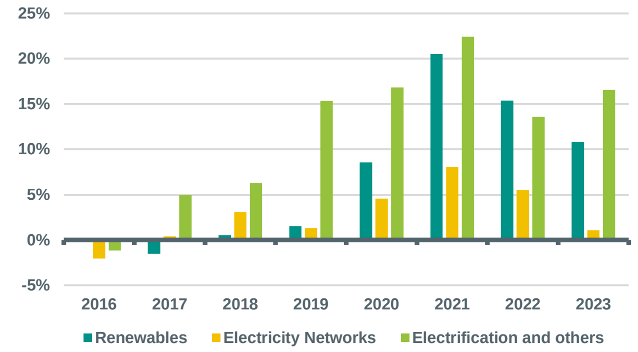
The transition is an economy-wide process where a development in one part affects, directly or indirectly, other parts. Accordingly, any evolving sectoral bottlenecks do not only affect the transition in the associated sector, but rather passthrough to other sectors as well. In this section we focus on different bottlenecks and challenges facing the energy transition.

Limited grid capacity

One of the prominent bottlenecks for the energy transition is the limited grid capacity, which does not only put limits on the expansion and roll out of renewables, but also discourages or postpones the electrification process. More precisely, the business case for wind and solar power rely on the possibility to connect these projects to the electricity grid. Meaning that, in the absence of suitable grid capacity, some renewable investments are either not happening or being postponed (which in this case, also negatively impacts returns and the financial viability of these projects). At the same time, in the absence of cheap renewable energy, electrification is halted or postponed. Furthermore, projects on alternative fuels that depend on renewables as a main input, such as green hydrogen, are also put on hold, affecting in consequence, the transition of hard to abate industries (such as shipping and steel) that do not have other alternative clean technology but green hydrogen.

European growth in grid investments is lower than in other clean energy investments

YoY growth, in percentages



Source: IEA, ABN AMRO Group Economics

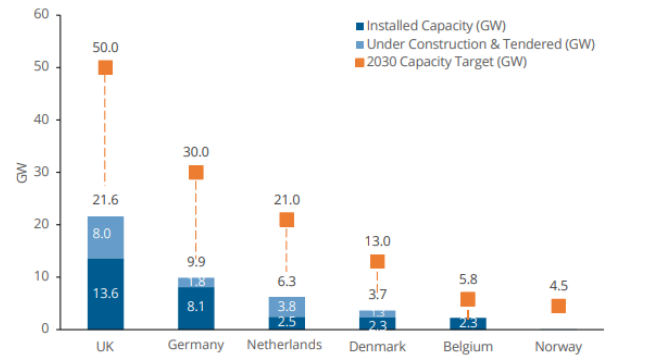
Specifically for wind power, there are queues for applications to connect to the grid networks, which along with an already strained grid, is limiting the possibilities to link to the transmission/distribution network for new renewable projects. This issue has floated to the surface in many countries such that the US, the Netherlands, and the UK[1]. The issue is particularly important for the development of offshore wind projects across Europe as illustrated by the planned capacity for 2030 (see the left side chart of the figure on the next page).

For the solar power, the energy crisis was a big catalyst to investments in distributed solar PV. This was most visible in the drastic increase in the solar investments last year. However, the deployment of distributed solar PV at a fast rate with the absence of grid capacity and grid level storage, translates into blackouts and negative prices, which decrease the incentives to invest.

In large parts of the Netherlands, the electricity grid is so full that no new major consumers, such as companies, can be connected in the coming years - until at least either the reinforcements of the electricity grid are ready or more flexible use is made from the net. This issue is demonstrated in the figure below (right), which depicts the regional grid capacity available for new connections in the Netherlands. The red colour implies a very congested electricity grid.

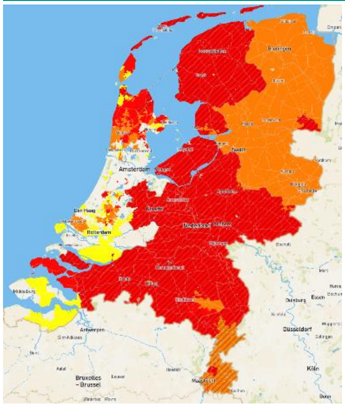
[1] In the United Kingdom, there are 371 GW of subscribed projects for grid connection, of which only 111-148 are expected to be connected (More here).

North sea offshore wind capacity



Source: Netherlands enterprise agency (RVO).

Dutch regional grid capacity



Source: Netbeheer Nederland. Version: 22-11-2023 at 13:15. Legend: Transparent: transport capacity available; Yellow: limited transport capacity available; Orange: no transport capacity available for the time being pending the outcome of the congestion management study; Red: no transport capacity available: congestion management cannot be applied.

Limited capacity in the grid is associated with long permitting and planning times and an old grid network. Additionally, the grid expansion process is complex, which involves many stakeholders (public and private) on a national and regional level, and requires therefore coordination on several levels. Moreover, there are long lead times for permitting grid projects because of inefficiency in permitting procedures, along with the extra time needed to adjust and adhere to new regulations. According to an IEA representative, this results in the time needed for grid extension projects (4 years on average) being almost double the one needed for development of other renewable projects, for example. This is an alarming sign: a slower transition because of insufficient grid capacity is magnified because of the mismatch in the timeframe for deploying grid extensions versus that needed for electrification or renewable deployments.

In the Netherlands, limits on nitrogen emissions represents an additional constraint on grid expansion. More precisely, the cap on nitrogen pollution affects the construction activities of infrastructure and electricity networks (**link**). As a result, some projects are currently on hold and awaiting clearer information on these limits.

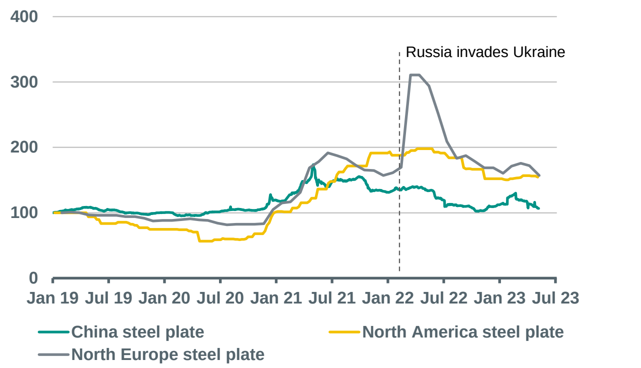
The long lead times also has a financial impact into the viability of these projects: an uncertain waiting queue makes it challenging for developers to estimate when the project will become commercially operating in order to capture revenues. This consequently affects their visibility or timing of future cash flows, which then finally deteriorates rate of returns of these projects.

Rising costs – but where are they coming from?

Raw materials and equipment costs

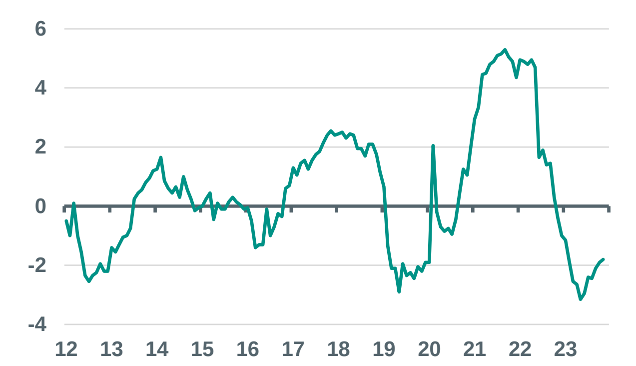
In the past months, we saw several renewable energy project developers (such as **Iberdrola**, **Vattenfall** and more recently, large developer **Orsted**) walking away from new projects as these have turned unprofitable. One of the key factors being mentioned as a reason for that decision is the rising input costs. Renewable energy technologies depend on the critical minerals, which makes them vulnerable to the tight supply or any shock affecting the markets of these materials. Looking specifically at the wind industry, wind turbines are mainly composed by steel (85%), followed by copper (4%), aluminium (4%) and lead (4%). Hence, the price of a wind turbine should, in theory, be directly linked to steel prices. But steel prices have come down from their 2022 peaks (see chart on the next page on the left) – so why are developers complaining of higher input costs?

Steel prices have come down…



Source: Bloomberg, ABN AMRO Group Economics

…And supply chain bottlenecks have collapsed

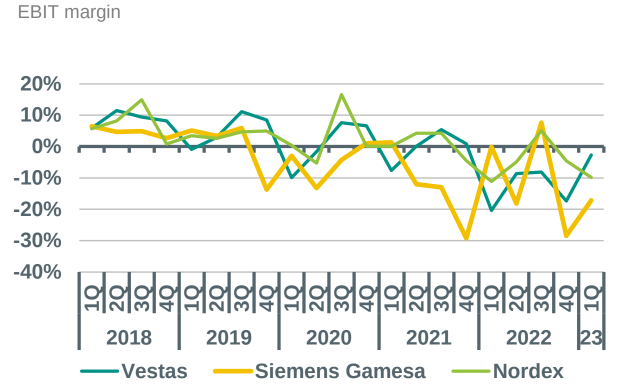


Source: ABN AMRO Group Economics

The answer to that might differ from technology to technology, but let's for example dig further into the wind industry situation to show that input costs are not exclusively driven by commodity prices.

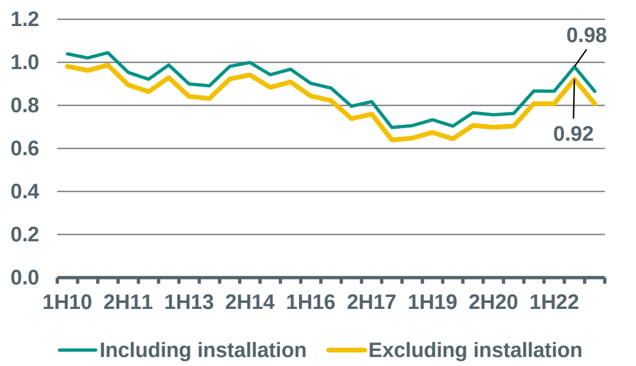
In the wind industry, while cost inflation from not only raw materials, but also higher freight prices and supply chain disruptions (particularly during Covid-19 period) have collapsed (see chart above on the right), wind turbine makers often sign framework agreements with off-takers, and there is, on average, a lag of more than 1 year between signing date and delivery date of a wind turbine. This means that the effects of reductions in input costs now may take a while to be felt by the market. Given this high lead time between signing and delivery date, wind turbine manufacturers were basically left with "biting the bullet" during the period of rising costs. These companies were stuck with contracts tied to "old" (and lower) off-taker prices, while having to incur higher costs from increasing raw materials prices and supply chain disruptions, which ultimately resulted in these companies having to operate with a loss (see chart below on the left). It sounds logical that, albeit benefitting from a reduction in input costs now, that these manufacturers are trying to recoup part of these historical losses by charging higher prices to their clients on existing / new orders, hence driving up wind turbine costs.

Wind turbine manufacturers operate with a loss…



Source: Bloomberg, ABN AMRO Group Economics

…Driving also higher wind turbine costs now



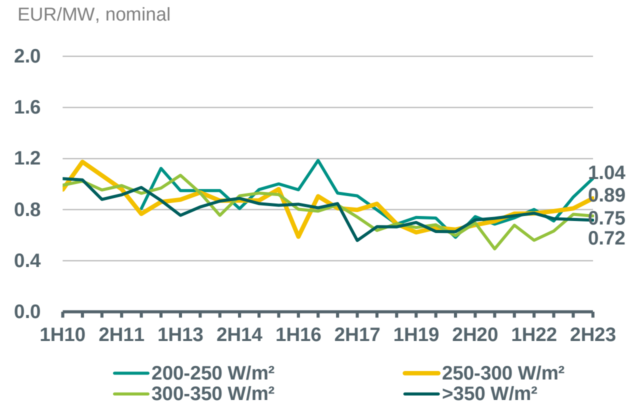
Source: BloombergBNEF, ABN AMRO Group Economics. Note: x-axis refers to signing date.

Technological advances

Another factor that is also driving higher investment costs are technological advances, which may increase productivity in the long-term, but also usually require larger investments upfront. Looking once again at the wind industry situation as an example, wind turbines have become larger, and more powerful, which are (partially) due to larger blades. Larger blades can increase capacity/load factors by generating more electricity at lower wind speeds, but this will also increase material use, which therefore adds to the turbine costs (see chart on the next page on the left). Hence, while on one hand, they increase productivity in the long-term, by allowing more wind to be captured (and hence more electricity to be produced), the upfront costs are also significantly higher. Besides additional material use, larger turbines also require larger vessels that are able to carry them, which in turn also requires bigger ports and reinforced quaysides that are able to carry this additional weight (among others). However, currently only 6% of the global vessel fleet is classified as 'very large' in terms of size, according to Equasis data of 2022. If one assumes that only these vessels are able to transport these longer blades wind turbines, developers could also be facing an issue with regards to shortage of vessels that can deliver the wind turbines they require. This lack of shipping capacity was also flagged as a reason by Orsted's CEO to pull out of new projects.

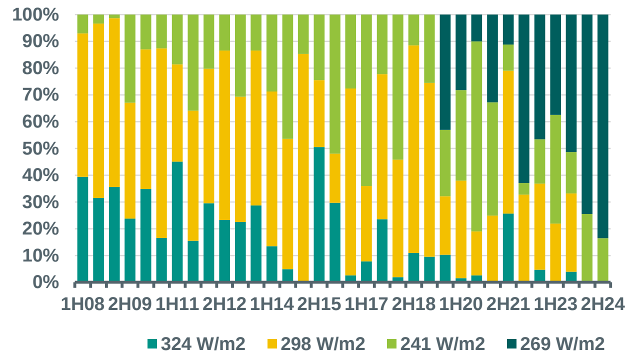
Over the years, there has been a significant increase in the demand for these larger (and usually lower power density) turbines (see chart below on the left side). This is mainly because developers seek to exploit lower-wind speed areas, such as in Western Europe or countries with limited site availability. Bloomberg BNEF estimates that around 80% of all turbines which are set to be delivered in 2024 are in the form of lower power density (that is, larger blades).

Turbines with larger blades are more expensive…



Source: BloombergNEF, ABN AMRO Group Economics. Note: x-axis refers to delivery dates. Lines indicate different power densities. The larger the wind turbine blade, the lower the power density.

…But demand for larger blade turbines has increased



Source: BloombergNEF, ABN AMRO Group Economics. Note: x-axis refers to delivery dates. Bars refer to average power density of different turbine classes. The larger the wind turbine blade, the lower the power density.

Transmission costs

Up until now, we have discussed costs that developers incur without taking into account transmission costs, or the costs incurred to get the electricity to the end-user. These may be partially or fully incurred by the developers. For example, zooming again into the wind industry, in the US and the UK, the developer is responsible for paying for and building the transmission from offshore wind assets to land. This is not the case in the Netherlands and Germany, where these transportation costs are incurred by the state-owned grid operator. The cost of grid interconnection can be a significant portion of the total cost of an offshore wind project, accounting for around 30% of the total all-in capex costs according to BloombergNEF.

In any case, regardless of incurring these costs directly of not, perhaps an even bigger issue as we just discussed is the limited on-shore grid capacity, where a connection delay also weigh then (indirectly) into the profitability of these projects.

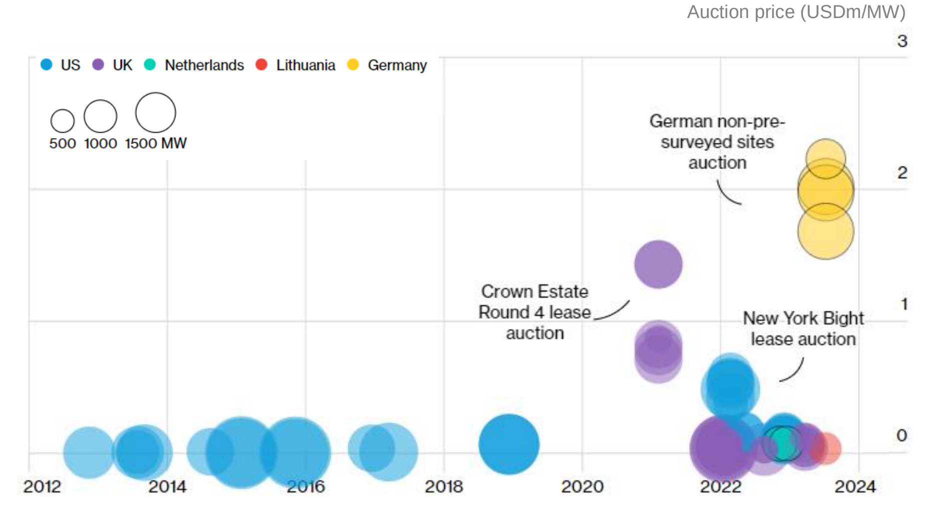
Development auction prices have also risen

On the other side of this, is also the fact that besides facing rising material costs, developers are also having to deal with higher auction prices for the sites on sea. The price of an auction reflects the cost paid by developers for development rights. Hence, directly impacting the investment cost (and consequently profitability) of a project.

The chart below shows the auction price of a few offshore wind projects in Europe and the US from 2012 onwards. More recently, an auction in Germany has brought the price to a new all-time high of EUR 1.6-2.1m/MW (see **here**). The actual cost incurred (from a cash-flow perspective) is also dependent on which jurisdiction the auction was undertaken. For example, while in Germany only 10% of the bid price is paid upfront, with the remaining paid over the first 20 years of project operation, in the US, developers must pay the full amount within 10 days of receiving a lease contract, which is usually only a few months after being claimed as the auction winner, thereby requiring huge up-front investment outlays.

A higher auction price means that the return per MW is lower. In some auctions, such as in the UK, the governments also sets a maximum power reference price, effectively capping what consumers can be charged. There is therefore clearly a mismatch between public and private interest: while governments work on trying to reduce energy prices for consumers, developers are faced with rising costs, which they need to pass on to consumers in order to maintain themselves profitable. The result of this was however a failed auction round by the UK government a few months ago. This drove the government to recently increase the maximum guaranteed price by 66% as an incentive to attract more developers – a higher price which will eventually feed into household's electricity prices.

Auction prices have gone up



Source: BloombergNEF, Note: x-axis refers to auction year. Bubble size shows site capacity. The Netherlands 2022 and UK 2022 auctions had price caps.

<u>The role of fiscal policies</u>

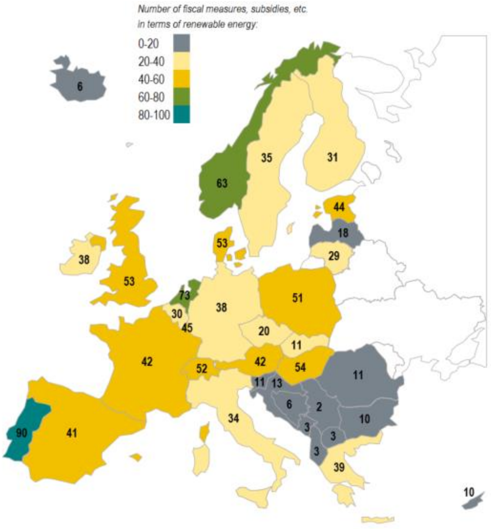
Access to finance is another obstacle for clean investments as these investments are capital intensive, long-term, and usually associated with uncertainties increasing the risk premium required by investors. Accordingly, the wide difference in fixed and operating costs between clean and fossil-based technologies requires an intervention to ameliorate the business case of low carbon technologies. Most governments in Europe have acknowledged this need and have designed different subsidy schemes to boost investments in renewables.

Below we show how many renewable subsidy opportunities are there currently per country in Europe. Leading with a number of 90 renewable energy subsidy schemes in Europe is Portugal. The Netherlands is second in this perspective with 73 subsidy schemes, closely followed by Norway.

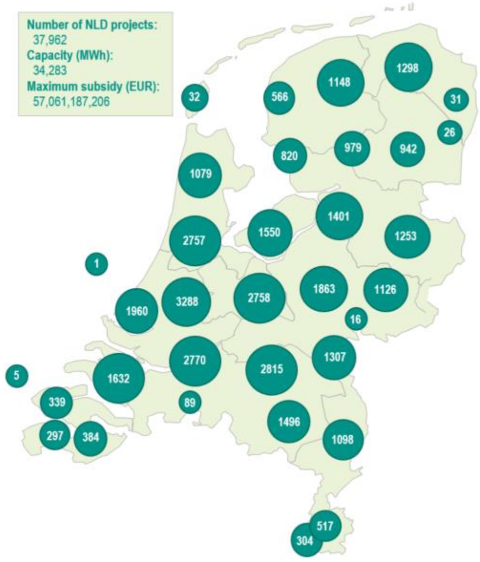
The availability of these subsidy schemes for renewable energy development has proved successful in almost all countries in Europe. The growth in the number of installations and installed capacity in solar PV, onshore and offshore wind has been substantial in recent years partly due to the subsidies. This has allowed especially SMEs, for example, to make relatively large use of the scheme, for whom such an investment is often financially challenging.

Subsidy measures renewable energy in EU and Netherlands

Number of subsidy schemes across Europe



Current renewable projects in NLD under SDE



Source: IEA, RVO, ABN AMRO Group Economics

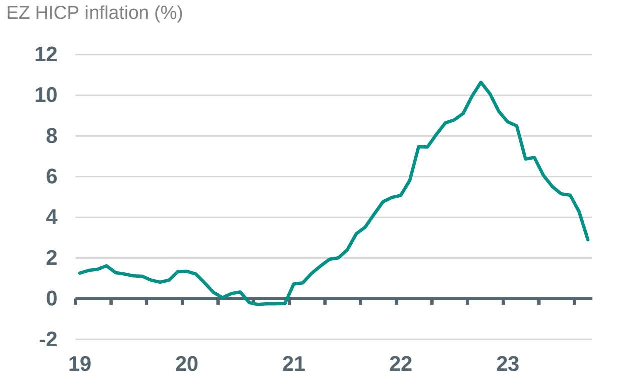
In the Netherlands, renewables projects are supported by The Sustainable Energy Production and Climate Transition Incentive Scheme (SDE++). This subsidy scheme targets renewable energy generation projects or the implementation of CO2 reduction technologies (CO2 storage/low-CO2 production (**link**)).The SDE++ is an OPEX subsidy that aims to subsidize the difference between the market value of produced energy and the cost of renewable energy production, guaranteeing the profitability of such project, where market value is calculated on annual basis and verified for the Netherlands. The renewable energy subsidy scheme (SDE++) is very popular. This is evident not only from the strong growth in the number of projects spread across the Netherlands, but also from the strong growth in the number of applications to the SDE++ subsidy.

Subsidy schemes for climate financing from the government will continue to play an important role in the coming years. Not only to boost capacity and installed capacity, but also to serve as bridging the financing gap for companies with less financial capacities. It is probably the most ideal way to further scale up investment in renewable energy in the coming years. That being said, a lack of those or a reluctance in updating policy levels (the strike price for SDE++ for example) taking into account market developments in a timely manner can turn these subsidies ineffective and have a negative impact on developer’s return.

Rising inflation and interest rates

Another layer is the fact that the macroeconomic scenario has changed significantly over the last few years. High inflation led governments to rise , interest rates, which directly affects projects’ financial viability. There is a vicious cycle where the profitability of large renewable projects relies on affordable finance, while access to this kind of finance relies on the profitability of these projects. This issue is becoming more and more visible in the offshore wind industry and even for distributed solar PV, where higher borrowing costs has its impact on the affordability of solar PV for small consumers.

Inflation has risen significantly



Source: Bloomberg, ABN AMRO Group Economics

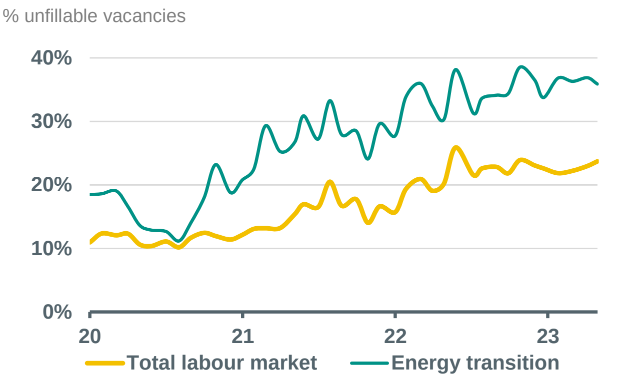
Which also drove higher interest rates and cost of debt

Source: Bloomberg, ABN AMRO Group Economics

Other challenges

All in all – different factors could be arising as headwinds for investments in renewable energy, undermining its business case. To add to that, the scarcity of skilled labour could also be a limiting factor for timely investments. In the considerable sustainability efforts that need to be made, professionals for the energy transition are essential but unfortunately hard to find. In the Netherlands, labour market shortages are substantial in general, but for occupation in the energy transition related activities they are even greater (**link**).This adds to inflationary pressures on different inputs for renewables, which made these investments out of the money.

Labour market is tight for the energy transition



Source: ABN AMRO labour market indicator

Managing the speed of the transition across different channels is also crucial for avoiding unnecessary delays or weakening the incentives to invest in clean technologies. For example, a higher share of renewables that simultaneously, increases the frequency of negative prices and reduces the capture rate[2], and in consequence, reduces the return on investment and the incentives to invest. Issues such as these could be tackled through batteries or hydrogen energy, for example, which also exemplifies how the energy transition should be tackled as a whole rather than on individual technologies.

Potential spill-overs

The impact of limited infrastructural capacity does not only affect the transition domestically, but it could limit the transition across borders. For example, the limited grid capacity would put limits to the transmission and trade of renewable electricity across borders. Also, the lack of charging stations for electric vehicles between countries could delay investments in the electrification of the transport sector. The problem of limited grid capacity and its effect on the transition is already starting to come to the surface for many European countries. In the Netherlands, plans for an energy tax on fossil fuels are objected by

[2] The capture rate is the portion of the price paid back to producers.

businesses, with the argument that the rise in fossil fuel costs will be associated with a limited capacity of electricity grids to meet the surge in demand by industrial electrification. Similarly, the limited German electricity grid transmission capacity is insufficient to match the imbalanced demand between the Northern and Southern states, nor does it allow for electricity trading between its neighbouring countries.

In addition, we should also look at the aforementioned problems in light of different transition policies. Carbon pricing's main function is to incentivize the transition towards low carbon technologies. Bottlenecks adversely affect the efficient functioning of carbon pricing and could have even much deeper effect such as triggering a crisis. For example, in Europe the EU-ETS is the flagship policy to reduce European emissions in key emitting sectors. EU-ETS is a cap and trade system, where a cap on emissions is set to decrease over time with a yearly linear reduction factor (now set at 4.2%) inducing an increase in the price of emission allowances that in turn should incentivize industries to adopt clean technologies. However, a bottleneck blocking the transition in power generation or heavy industries while carbon prices keep rising would incorporate additional costs to companies, where the international competitiveness of these companies deteriorate with no possibility to switch to clean alternatives. The latter impact could lead to bankruptcies and even trigger a transition related crisis.

Case study: the business case for offshore wind

Are offshore wind projects becoming financially unviable?

So how do these headwinds boil-down to actual returns for investors in wind power developments? To make the aforementioned challenges and bottlenecks a little bit more practical, we have constructed a model which tries to quantify how the current environment negatively affects renewable energy investments. For that, we use the (offshore) wind industry as an example.

Hence, in this section, we test a hypothetical offshore wind project's internal rate of return (IRR) by using different input variables, including the cost of materials, higher interest rates, and long-term contracted electricity prices. While we rely on publicly disclosed prices, and hence, may not have a full picture in terms of actual costs, the idea of this exercise is to give the reader a closer look into developer's claims that projects are indeed unprofitable. We also include a table that shows the sensitivity of the IRRs to different input assumptions.

Model assumptions

The table below summarizes our key model assumptions. We assume that 70% of the project is financed through debt, with only the remaining via equity. Furthermore, we assume that the wind farm project is operated for, and fully depreciated after 25 years, and that there is no salvage value. After these 25 years, the developer needs however to incur decommissioning costs related to removing the wind farm from the ocean. These are estimated at around USD 135,000/MW (see **here**). We use BloombergNEF as source for our estimates on costs (including development and fixed costs). We also assume – in line with the current framework in countries such as Netherlands and Germany – that the transmission costs are incurred by the grid operator, and not by the developer. This results in total investment costs of EUR 1.8m/MW installed, excluding maintenance capex. We also assume that every year, around 0.65% of the wind farm utilization is reduced due to wear & tear– this is a conservative approach and in line with other sources such as BNEF. Cost of debt is assumed to be 4%, in line with the average 10y bond yields for IG (North-Western) European integrated utility companies (incl. developers). We also assume short-term inflation to be 6% (the YTD average in the Euro-area, as of November), which crawls back to 2% in the long-term. In this exercise, we do not assume the contentious shipping costs as separate investment item, as these should be part of the turbine costs. However, as we have previously pointed out, delays in terms of shipping (regarding, for example, vessel shortage) could also be a key input to determine whether a project is profitable or not. We also assume that variable costs (including maintenance) are high in the first years, but decline by a fixed rate per year up until it reached 60% of the initial value within 15 years. Furthermore, it takes 2 years to get the windfarm from FID to be operational. Debt is supposed to be repaid in 20 years. In terms of revenues, we assumed a EUR 53/MW price, in line with Pexapark's latest composite PPA price (we note this price is not exclusive for wind energy). As a conservative approach, we do not assume any subsidies, as these provide an upside to valuations. However, below we include as well a sensitivity analysis, where we highlight what the impact of lower costs would have on IRR.

Assumptions:	
generation degradation py	0.65%
LT inflation	2.00%
ST inflation	6.00%
gearing (D/E)	70%
depreciation (%)	4%
salvage value	0%
tax rate	25%
asset life (yrs)	25
loan length (yrs)	20
fixed opex (eur/mw/yr)	37,066.11
variable opex (eur/mw/yr)	74,132.22
variable opex declining rate py	4%
variable opex % in 15y	60%
capacity factor	40%
plant capacity (mw)	20
PPA price	53.00
interest rates (cost of debt)	4.00%
decommissioning costs (EURm/MW)	0.14
development costs (EURm/MW)	0.06
turbine costs (EURm/MW)	0.94
construction costs (EURm/MW)	0.72

Please refer to the appendix for the full investment horizon and net cashflow table behind this financial model.

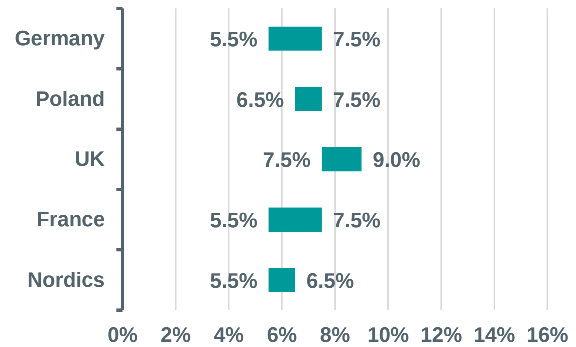
Offshore wind farm's returns are not enough to meet developers' hurdles
Our financial model (tailored to the European situation) calculates then the IRR, which should be then compared with developer's hurdles. As a rule of thumb, when a project IRR is lower than the required hurdle, the developer is unlikely to undertake the project as it might be dilutive to its total returns.

Based on the assumptions as highlighted above, our IRR is estimated to be 4.1%. This compares to, for example, a negative 1.4% of our estimates in a model which is more tailored to the US situation (see **here**).

While 4.1% might be seen as an attractive return, we compare this figure to the latest minimum return requirements for offshore wind in different regions (see chart below). According to BloombergNEF, a hurdle IRR could be as low as 5.5% (such as in Germany, France and Nordics), but also as high as 9%, such as in the UK (see chart on the next page). Differences are mainly related to market characteristics. For example, in countries where the PPA market is strong, interest for stable cashflow is obviously higher and therefore investors are willing to accept a lower targeted rate of return. On the other hand, competitive markets also make investors reduce their required return as a result of fear of losing out on investment opportunities. All in all, It seems that the 4.1% seems to still be below the minimum required by European developers for the project to be deemed financially viable.

Required rate of returns vary per jurisdiction

Levered equity IRRs for COD of wind



Source: BloombergNEF, ABN AMRO Group Economics. Note: BNEF estimations are from conversations with wind investors active in these markets.

Certainly, as we previously pointed out, our model is bounded by our assumptions. Changes in our assumptions would certainly also lead to changes in our project's IRR. For example, using the 66% higher maximum guaranteed price set by the UK government during auctions instead of our assumption of EUR 53/MW already increases the IRR from 4.1% to 13%.

With that in mind, the tables on the next page show how IRR would change if we also relax or tighten some of our assumptions. We focus on, for example, the cost of debt and inflation, which have risen significantly due to macroeconomic conditions. But also as we pointed out, turbine costs are also a relevant (and significant) part of our cash outflow assumptions. Hence, we also analyse what would happen if turbine costs were to rise even more. As we previously mentioned, our source for overall costs (development, turbine, transmission and construction costs) are as per latest BloombergNEF estimates. However, other sources indicate these costs have risen significantly. IRENA, the international renewable energy agency, estimates these could already be on average as high as around EUR 4m/MW (including transmission costs – we assume this to be around EUR 3.3m/MW without these costs). With that in mind, we also evaluate what would happened to our assumed returns if total costs increase from our current assumption of EUR 1.85m/MW to as high as EUR 3.3m/MW. For the purpose of this exercise, we increase turbine costs and maintain all other costs (development, transmission and construction) constant. Lastly, we also relax (and tighten) our PPA assumption by 5% to analyse how this also feeds into estimated IRRs. PPA prices depend greatly on jurisdiction, so we are keen on understanding how this would impact our estimated IRR.

The table below shows, for example, that when total costs go up to IRENA's estimation of EUR 3.3m/MW, the IRR drops to a negative 3.7%. Also cost of debt is an important driver of project's financial viability. An increase of 50bps in cost of debt results in around 30bps decrease in IRR. Rising PPA prices could also help to make up for the low return. Our model estimates that a 30% increase in PPA prices from our current assumption of EUR 53/MW would result in IRR jumping from a 4.1% to a 11.8%. This analysis also shows us that, in this model, IRR is more sensitive to inputs such as turbine costs and PPA prices, rather than inflation and cost of debt.

		cost of debt				
		3.50%	**3.75%**	**4.00%**	**4.25%**	**4.50%**
turbine costs (EURm/MW)	**0.94**	4.5%	4.3%	4.1%	3.9%	3.8%
	1.44	1.1%	0.9%	0.7%	0.6%	0.4%
	1.94	-1.4%	-1.6%	-1.8%	-1.9%	-2.1%
	2.44	-3.4%	-3.6%	-3.7%	-3.9%	-4.1%
	2.94	-5.0%	-5.2%	-5.3%	-5.5%	-5.7%

		PPA price				
		38.29	**45.05**	**53.00**	**60.95**	**70.09**
ST inflation	**2.0%**	-5.0%	-0.8%	3.3%	6.9%	10.8%
	3.0%	-4.8%	-0.6%	3.5%	7.1%	11.0%
	4.0%	-4.6%	-0.4%	3.7%	7.3%	11.3%
	5.0%	-4.4%	-0.2%	3.9%	7.6%	11.5%
	6.0%	-4.2%	0.0%	4.1%	7.8%	11.8%

Source: ABN AMRO Group Economics. Note: grey area indicates current model assumption

Recommendations on possible remedies

Even with a better government support in place in terms of subsidies, as long as bottlenecks exists, the transition will not go forward according to plan. Authorities have an essential role in managing the transition and mitigating the effect of bottlenecks or any adverse change in the business environment. For instance, the EU authorities should keep the emission allowance (EUA) price in check by the usage of Market Stability Reserve until bottlenecks are resolved or an emerging shock has elapsed.

Also, a timely update for policy levels (such as we have seen with the government raising the maximum electricity allowed price in the UK) is essential to avoid unnecessary delays and associated additional costs, in particular given the sector and industry's fast developments. Moreover, reforms are needed to facilitate the extensions of grid limited capacity as soon as possible. For example, auction redesigns, the easing of licencing procedure, and enforcing shorter deadlines for permitting applications on national and European levels.

Also, a proactive approach should be adopted by authorities to revaluate and investigate any potential bottlenecks that could emerge during the transition process in advance. For instance, revisiting current regulation from the transition perspective in order to identify any regulatory barriers that could hinder the deployment of clean technologies, either directly or indirectly by impeding potential business cases that could be pursued in a more supportive or effective regulatory environment. Additionally, tailored training and reskilling programs aimed for workers in weakened industries should be further developed to help meeting rising demand from transition needed industries.

Appendix: Overview of ABN AMRO's offshore wind viability model

		t=1	t=2	t=3	t=4	t=5	t=6	t=7	t=8	t=9	t=10	t=11	t=12	t=13	t=14
	total	development	construction	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation
Capex Costs															
Development	**-1,100,000**	-1,100,000	0												
Construction of Plant	**-14,360,000**	0	-14,360,000												
Equipment	**-18,800,000**	0	-18,800,000												
Transmission	**0**	0	0												
total capex	**-34,260,000**														
fixed opex	**-18,569,714**			-741,322	-743,359	-743,359	-743,359	-741,322	-743,359	-743,359	-743,359	-741,322	-743,359	-743,359	-743,359
variable opex	**-26,066,236**			-1,482,644	-1,425,515	-1,370,586	-1,317,775	-1,266,998	-1,218,177	-1,171,238	-1,126,108	-1,082,716	-1,040,997	-1,000,885	-962,318
opex declining rate per year	**3.9%**														
Decommissioning costs	**-2,700,000**														
% of debt	**70%**														
equity injections	**11,048,000**	1,100,000	9,948,000												
equity cash flows		-1,100,000	-9,948,000												
debt BoP		0		23,212,000	22,051,400	20,890,800	19,730,200	18,569,600	17,409,000	16,248,400	15,087,800	13,927,200	12,766,600	11,606,000	10,445,400
debt repayment				1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600
debt EoP			23,212,000	22,051,400	20,890,800	19,730,200	18,569,600	17,409,000	16,248,400	15,087,800	13,927,200	12,766,600	11,606,000	10,445,400	9,284,800
debt interest			0	928,480	882,056	835,632	789,208	742,784	696,360	649,936	603,512	557,088	510,664	464,240	417,816
total debt financing needed	**23,212,000**														
funding total (w/interest)	**34,260,000**														
EBITDA				1,634,386	1,725,505	1,826,068	1,923,550	2,031,139	2,109,600	2,198,321	2,284,271	2,381,075	2,448,130	2,526,172	2,601,705
D&A				1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400
EBIT				307,986	399,105	499,668	597,150	704,739	783,200	871,921	957,871	1,054,675	1,121,730	1,199,772	1,275,305
EBT				-620,494	-482,951	-335,964	-192,058	-38,045	86,840	221,985	354,359	497,587	611,066	735,532	857,489
Taxes paid				-155,124	-120,738	-83,991	-48,014	-9,511	21,710	55,496	88,590	124,397	152,767	183,883	214,372
ITC	**NO**			0											
generation															
operation (%)				100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
generation degradation (%)				0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%
utilitsation (%)				98.0%	97.4%	96.7%	96.1%	95.4%	94.8%	94.1%	93.5%	92.8%	92.2%	91.5%	90.9%
days in a year				365	364	364	364	365	364	364	364	365	364	364	364
hours in a year operating				8585	8504	8448	8391	8357	8277	8221	8164	8129	8050	7993	7937
generation mwh				68,678	68,036	67,582	67,127	66,856	66,219	65,765	65,310	65,034	64,402	63,948	63,493
inflation				6.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
inflation index			100%	106.00%	108.00%	110.00%	112.00%	114.00%	116.00%	118.00%	120.00%	122.00%	124.00%	126.00%	128.00%
revenue				3,858,353	3,894,379	3,940,013	3,984,684	4,039,459	4,071,137	4,112,919	4,153,737	4,205,114	4,232,486	4,270,415	4,307,382
net operating cash flow		-1,100,000	-9,948,000	1,634,386	1,725,505	1,826,068	1,923,550	2,031,139	2,109,600	2,198,321	2,284,271	2,381,075	2,448,130	2,526,172	2,601,705
FCFE	**12,247,445**	-1,100,000	-9,948,000	-299,571	-196,413	-86,173	21,757	137,266	230,930	332,289	431,569	538,991	624,100	717,449	808,916
IRR	**4.1%**														

	t=15	t=16	t=17	t=18	t=19	t=20	t=21	t=22	t=23	t=24	t=25	t=26	t=27
	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation	operation
Capex Costs													
Development													
Construction of Plant													
Equipment													
Transmission													
total capex													
fixed opex	-741,322	-743,359	-743,359	-743,359	-741,322	-743,359	-743,359	-743,359	-741,322	-743,359	-743,359	-743,359	-741,322
variable opex	-925,238	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587	-889,587
opex declining rate per year													
Decommissioning costs													-2,700,000
% of debt													
equity injections													
equity cash flows													
debt BoP	9,284,800	8,124,200	6,963,600	5,803,000	4,642,400	3,481,800	2,321,200	1,160,600	0	0	0	0	0
debt repayment	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	1,160,600	0	0	0	0	0
debt EoP	8,124,200	6,963,600	5,803,000	4,642,400	3,481,800	2,321,200	1,160,600	0	0	0	0	0	0
debt interest	371,392	324,968	278,544	232,120	185,696	139,272	92,848	46,424	0	0	0	0	0
total debt financing needed													
funding total (w/interest)													
EBITDA	2,688,757	2,745,480	2,779,558	2,812,672	2,859,162	2,876,012	2,906,237	2,935,499	2,978,463	2,991,134	3,017,507	3,042,917	382,313
D&A	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400	1,326,400
EBIT	1,362,357	1,419,080	1,453,158	1,486,272	1,532,762	1,549,612	1,579,837	1,609,099	1,652,063	1,664,734	1,691,107	1,716,517	-944,087
EBT	990,965	1,094,112	1,174,614	1,254,152	1,347,066	1,410,340	1,486,989	1,562,675	1,652,063	1,664,734	1,691,107	1,716,517	-944,087
Taxes paid	247,741	273,528	293,653	313,538	336,766	352,585	371,747	390,669	413,016	416,183	422,777	429,129	-236,022
ITC													
generation													
operation (%)	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
generation degradation (%)	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%	0.65%
utilitsation (%)	90.2%	89.6%	88.9%	88.3%	87.6%	87.0%	86.3%	85.7%	85.0%	84.4%	83.7%	83.1%	82.4%
days in a year	365	364	364	364	365	364	364	364	365	364	364	364	365
hours in a year operating	7902	7823	7766	7710	7674	7596	7539	7482	7446	7369	7312	7255	7218
generation mwh	63,212	62,585	62,130	61,676	61,390	60,768	60,313	59,859	59,568	58,951	58,496	58,042	57,746
inflation	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
inflation index	130.00%	132.00%	134.00%	136.00%	138.00%	140.00%	142.00%	144.00%	146.00%	148.00%	150.00%	152.00%	154.00%
revenue	4,355,318	4,378,426	4,412,503	4,445,618	4,490,070	4,508,957	4,539,182	4,568,444	4,609,372	4,624,079	4,650,452	4,675,862	4,713,222
net operating cash flow	2,688,757	2,745,480	2,779,558	2,812,672	2,859,162	2,876,012	2,906,237	2,935,499	2,978,463	2,991,134	3,017,507	3,042,917	382,313
FCFE	909,024	986,384	1,046,760	1,106,414	1,176,099	1,223,555	1,281,042	1,337,806	2,565,447	2,574,950	2,594,730	2,613,788	618,335
IRR													