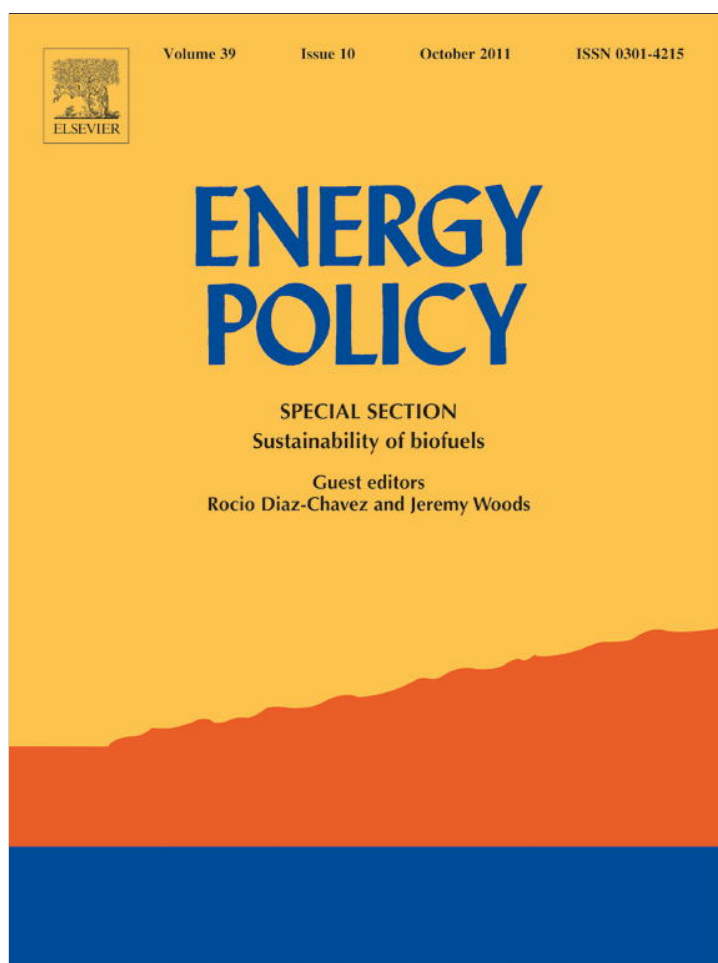


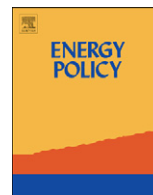


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Regulatory road maps for the integration of intermittent electricity generation: Methodology development and the case of The Netherlands ☆, ☆ ☆

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ABSTRACT

The envisaged increase in the share of electricity generation from intermittent renewable energy sources (RES-E) like wind and photovoltaics will pose challenges to the existing electricity system. A successful integration of these sources requires a cost-efficient use of system flexibility. The literature on the options to improve system flexibility, and thus the costs of successfully integrating intermittent electricity generating units, is still growing but what is lacking is an overarching systematic view on when to adopt which option in particular energy systems. This paper aims to bridge this gap in literature. We use existing insights on market and network integration of intermittent electricity sources within a regulatory road map framework. The framework allows policy makers and other electricity system stakeholders to arrive at a consistent strategy in dealing with integration issues over a longer period of time. In this contribution we present and explain the framework and apply it for the case of The Netherlands.

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1. Introduction

The European Commission has formulated clear and ambitious targets for enhancing the sustainability of the European economy in 2020 i.e. 20% of final energy demand should be supplied by renewable energy, and both a reduction of 20% of CO₂ emissions and 20% energy savings have to be achieved. Particularly the first goal implies that electricity generation from renewable energy sources (RES-E) has to increase to about 35%, since the contribution of other sectors like heating and cooling to this goal is envisaged to be lower. This is generally perceived as an ambitious target, as there is a large gap between the current and required RES-E share for the majority of EU member states. In countries without large hydro or biomass potential a large penetration of

RES-E from wind, photovoltaics (PV) and heat-led combined heat and power (CHP) is essential for achieving the EU RES targets. These sources are considered to be of ‘intermittent’ nature, since they are either dependent on the weather (wind and PV), which makes electricity output more variable and less predictable, or on heat demand (heat-led CHP), which limits the controllability of the electricity produced.

An increase in intermittent generation has profound implications for the power system as a whole, for two reasons. Firstly, power flows in networks will become more variable as a result of the increase in generation variability. Besides, more power will be fed-in the grid at lower voltage levels (‘distribution grid’), sometimes exceeding demand and implying upward flows to higher voltage levels (‘transmission grids’) for transportation of electricity to other load centers. Secondly, when the RES-E penetration reaches substantial levels, the intermittent power supply implies an increase in the need for balancing power, and more variability in market prices.

In other words, more system flexibility is needed to facilitate the large-scale integration of intermittent sources. A large number of options are available for this purpose, varying in nature and in cost-effectiveness. For example, additional flexibility could be provided by increasing network interconnections with neighboring electricity systems or by realising large-scale energy storage. How can we ensure that the overall electricity system costs of providing additional flexibility remain as low as possible? In general this involves the adoption of the most cost-efficient

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flexibility options over time. A (too) large increase in the costs of flexibility due to increased penetration of intermittent electricity generation will certainly not act as a stimulus for further investment in these type of generation technologies.

The impacts of an increasing amount of intermittent generation have already been widely researched (Dale et al., 2004; Holttinen, 2005), and also a large number of 'response' options have been identified (Gross, 2004), including interconnections (Zvingilaitė et al., 2008), storage (Mariyappan et al., 2004; DeCarolis and Keith, 2004) and demand response (Strbac, 2008). What to our knowledge has not been done before is the development of a systematic framework that uses this existing body of knowledge to provide more country and time period specific recommendations on the most cost-efficient way to deal with increased integration costs due to intermittent generation. Our research effort has been focussed on exactly this gap. More specifically we use the methodology of road map building to construct a framework that systematically links: (1) the amount of intermittent generation within an electricity system, (2) the impact this has on the electricity system, (3) the options to deal with this additional need for flexibility and (4) the impact of country or electricity system specific characteristics upon (1)–(3). The framework we come up with is validated with an application to the case of The Netherlands.¹

The structure of the paper is as follows. Section 2 outlines the background for our analysis; the need for additional system flexibility to accommodate impacts of increasing generation from high shares of intermittent RES-E. In Section 3 we present our regulatory road map methodology. Section 4 applies this methodology to The Netherlands. Section 5 concludes and provides suggestions for further research.

2. Background

2.1. Impact of intermittent generation on electricity system costs

Adding intermittent generation to the system does have major implications for different power system segments: generation, balancing and wholesale markets and transmission and distribution networks.

The impact on generation is caused by the fact that RES substitute energy and capacity of conventional power plants. Substitution of energy leads, apart from positive impacts, such as reduction of fossil fuel consumption and associated CO₂ emissions, also to part-loaded operation of conventional power plants and to the increased cycling of their operation (more start-ups and shut-downs). Both outcomes bring about higher costs and emissions. Substitution of capacity decreases the conventional generation required to cover annual peak demand. Different RES and Distributed Generation (DG) technologies will be able to displace different amounts of capacity, but generally RES displaces more energy than the capacity of conventional generation due to the higher variability and lower predictability of its production. Consequently, flexible generators with high ramping capabilities (gas-fired and hydro based generators) have to be available for critical system times (for instance high demand and low intermittent RES supply concurrently). On the other hand, base load conventional plants are shifted to the margins and may see a reduction in their profitability with increasing penetration of RES and DG.

Through the increase in intermittent RES-E production also the need for more balancing power may rise. Balancing power is required for different time frames ranging from within 30 s

(primary frequency control), within 15 min (secondary frequency control) or after 15 min (tertiary frequency control). The need for balancing power will increase with higher penetrations of intermittent sources, making the system facing increasing balancing costs. The additional cost of primary frequency regulation is considered to be small. In case wind power penetration increases with 20%, the demand for secondary frequency control is expected to increase – *ceteris paribus* – with 3–7% of peak load or capacity in the Nordic countries (Holttinen, 2004).² Generally, the demand for secondary frequency control is expected to grow with a higher percentage of peak load when wind power penetration exceeds 20–30% of gross demand (a.o. indicated by Gross et al., 2006). The demand for tertiary frequency control will rise in the same proportion as the demand for secondary frequency control, since the former usually supports the latter in performing its task.

Through incorporating more RES and CHP production in the system, intermittency is passed through from production to network operation, which affects both distribution and transmission networks. Part of the intermittent RES will be connected to distribution networks. Apart from associated technical problems like voltage rise problems in rural networks and an increase in fault levels in urban networks (Strbac et al., 2006), power flows may change as the system architecture changes considerably (Ramsay et al., 2007); with a higher penetration of DG, a large number of (intermittent) renewable generators will be connected to distribution voltage levels instead of mainly a small number of large generators connected to higher voltage levels. This influences both the direction and magnitude of the power flows on the network.

On one hand, when more power is supplied to distribution levels, less power has to be transferred from the transmission level downwards in the chain to the end consumer. On the other hand, a higher penetration of DG implies that power supply from intermittent generation sometimes exceeds local load and needs to be exported to other regions via transmission networks (Ramsay et al., 2007). As a consequence, Distribution System Operators (DSOs) have to deal with reverse flows and generally a higher frequency of different and extreme situations in network management. This translates often in higher distribution capacity requirements as the 'fit-and-forget' network planning philosophy in distribution networks aims to resolve all possible network congestion situations beforehand through network reinforcements (transformers, overhead lines and network cables). Combined with the higher diversity of power flows, this practise means limited utilization of new network reinforcements, which brings about high costs (Van der Welle et al., 2009).

RES-E is also increasingly connected directly to transmission networks (e.g. offshore wind parks) managed by Transmission System Operators (TSOs). Besides these additional power flows, TSOs have also to deal with reverse flows coming from (rural) distribution networks with surplus of power, which needs to be transferred to areas with shortage of power. Hence, additional network reinforcements may be needed, although to a more limited extent than in distribution since transmission is already actively managed; TSOs already dispose of real-time network monitoring and control possibilities like network switching, reconfiguring, or using reactive compensators.

2.2. Response options

Clearly, the fast growth of RES-E production in line with EU 20-20 goals has substantial impacts on electricity networks,

¹ Van der Welle et al. (2009) provide an application to five countries: Denmark, Germany, The Netherlands, Spain and the United Kingdom.

² This percentage is highly dependent on the system under consideration, especially security of supply requirements of system operators and the balancing market design chosen.

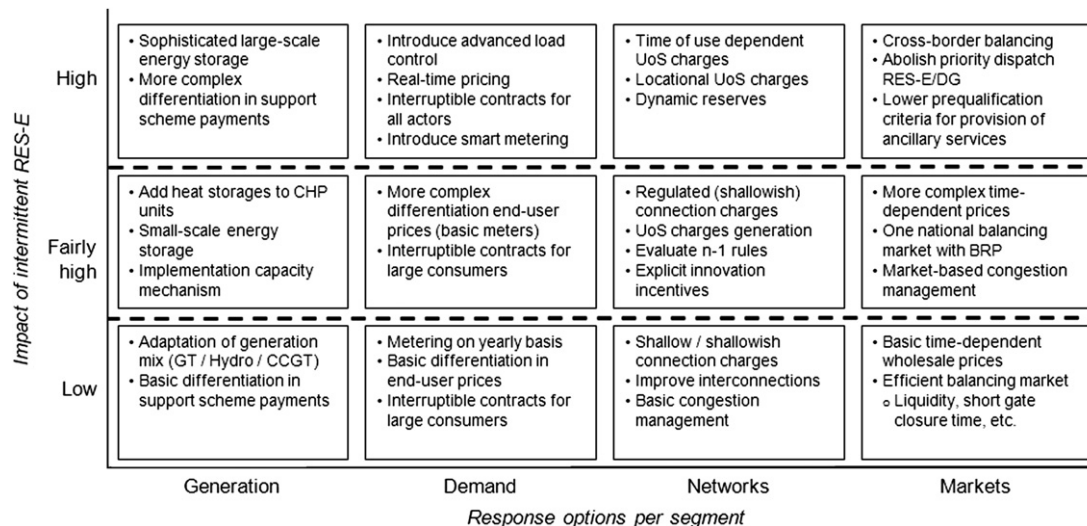


Fig. 1. Indicative response options per segment.

system balancing and markets. Consequently, system integration costs are expected to increase strongly, in turn endangering this fast growth of RES-E. For preventing such a scenario to occur, cost reducing measures to react to these cost impacts should be considered (i.e. response options). In Fig. 1 we summarize some of the main technical and institutional response options. This Figure is not exhaustive and is only meant for illustrative purposes.

The different electricity market value chain elements used throughout the RESPOND study are listed horizontally. On the vertical axis we depict three qualitative degrees of intermittent RES-E impacts within the electricity system. The impact of RES-E on the electricity system, which results from either a high absolute level of intermittent RES-E or a large relative share of RES-E, can be qualified as low, fairly high or high. This classification should illustrate the principle that implementation of certain response options should be proportional to the problems created by more and more intermittent RES-E.³ At low levels of intermittent RES-E, with relatively little problems caused in the electricity system, relatively simple response options should be implemented. When the share of intermittent RES-E increases to very large levels, and problems are more severe, more complex and costly response options need to be implemented. For example, shorter gate closure times of trade markets may reduce system balancing requirements already in the case of low intermittent RES-E impacts, while active network management may render distribution network capacity extensions more cost efficient in the case of medium to high intermittent RES-E impacts. More complex response options however should not be considered whenever there is still ample potential to implement less complex and less costly response options.

3. Methodology

3.1. Introduction

Since power systems and their concomitant costs vary widely between EU countries according to different system

characteristics, different countries thus need to take different actions to increase the flexibility of their respective power systems in the most cost-efficient manner up to 2020 and beyond. Besides the timing of these actions may differ according to the actual development of RES-E, demand and other power system characteristics. This requires a systematic assessment of both the impacts and response options for different countries and their timing. To our knowledge, regulatory roadmaps are the only method, which can deal with all these different elements in a consistent and plausible way over a longer period of time.

Hence, the basic methodology applied in this paper is that of road-map building, and more specifically building a road map for regulatory actions. The principle of road maps in general has been derived from technology road maps (Van Sambeek et al., 2003). A regulatory road map presents possible routes of regulatory development and indicates important intermediate points in time for a smooth transformation of the electricity system in order to comply with EC renewable energy targets. Its basic building blocks are: (1) different stages of market integration, and (2) different stages of network integration. We explain these building blocks consecutively below. These culminate in the regulatory road map tool used in the construction of national regulatory road maps.

3.2. Stages of market integration

Market integration concerns the integration of new RES-E generation units in different markets: electricity wholesale market, and the markets for system balancing and other ancillary services. Analogous to Van Sambeek et al. (2003) we have precisely defined three different stages for market integration. The three stages respectively relate to low, fairly high and high levels of RES-E in the system and can be associated with various levels of negative system impacts caused by this amount of RES-E as well as consistent sets of measures to overcome the system impacts. In addition, the different stages specify the role that RES-E plays, either actively or passively in electricity markets in each stage. With an increase in the share of intermittent RES-E, RES-E generation reaches an equal level as centralized (non-intermittent) generation on the various energy markets. In the transition towards a situation with a high penetration level of RES-E, providing RES-E equal opportunities implies that additional incentives are realised that favor additional penetration. In the final end stage, RES-E might be given an equal role to play in the different sub-markets of the electricity system (wholesale market, balancing market and other ancillary services market),

³ For simplicity, in the remainder of this paper the response options of the different segments are attributed to either market or network integration. Consequently, the system transformation process can be described with two dimensions: market and network integration.

Table 1
Stages of market integration.

Stage	Description	Market integration issues	Recommendations
A Protected niche market	● Low penetration level of RES-E ● RES-E operates outside markets for electricity and ancillary services	● Variable RES-E negligible impact on markets ● No access to wholesale and other markets	● Focus on economic viability RES-E, priority dispatch, feed-in tariff regime
B RES-E in the market	● Fairly high penetration level of RES-E ● RES-E participates in electricity market ● RES-E participates partly in supply side of ancillary services market	● No/limited RES-E participation in markets ● Fairly high impact in system balancing costs ● RES-E has limited to fairly high effects on market prices ● Demand response limited due to lack of demonstration of smart metering and smart home area networks at LV, as well as lack of time-differentiated prices ● Combination of RES-E support schemes and lack of negative prices at power exchanges (PXs) decreases deployment of RES-E flexibility	● Move to feed-in premium ● Possibilities for provision of ancillary services by RES-E ● Regime of balancing responsible parties & short gate closure time of trade markets ● One-stop shop approach for flexible generation ● Demonstration projects on smart metering and smart home area networks to prepare for introduction of smart metering at low voltage level ● Introduce/oblige (simple) time-differentiated prices ● Possibility of negative prices at PX
C Active RES-E	● High penetration level of RES-E ● RES-E provides all kind of ancillary services when profitable	● RES-E enters other markets (ancillary services, downward balancing) ● Substantial increase in system balancing cost ● RES-E has fairly high to high effects on market prices ● Demand-side involvement in balancing and ancillary services market	● RES-E involvement in all markets if cost-efficient and through VPPs if necessary ● Introduce cross-border balancing ● Contract balancing power outside the market if insufficient balancing power is made available in the market ● Implementation of smart metering and real-time pricing ● Virtual power plants for demand aggregation, increased use of interruptible contracts

but this equal role should only be facilitated when deemed optimal from a social welfare perspective. After all, there are particular differences between the inherent characteristics of conventional electricity generation technologies and RES-E electricity generating technologies like load following capabilities and predictability, which might give rise to differential treatment of the two. Equal treatment could possibly lead to suboptimal electricity market outcomes from a social welfare point of view acknowledging the fact that some production technologies have more favorable characteristics than others.

For the purpose of constructing regulatory road maps each stage is accompanied by specific criteria, linking the major issues in a specific country (here: The Netherlands) with regulatory measures. We refer to Table 1 for an overview of the different market integration stages we distinguish. As the first step, observing the penetration level of intermittent RES-E and their participation in markets, one can defer the likely impact level, and relate this level via the information in the table, to a particular stage of market integration. General market integration issues that are likely to occur with this impact level are shown in the next column. In order to mitigate or overcome the impact of these market integration issues, the last column provides institutional and technical response options, which are recommended to be implemented.

For instance, in the case of a fairly high penetration level of intermittent RES-E i.e. between 10% and 30%,⁴ balancing costs may substantially increase. Among others, this increase can be mitigated by implementing shorter gate closure times of trade markets and hence the possibility to adapt RES-E production schedules closer to real-time.

Other central market integration issues, identified by extensive literature review within the RESPOND project (Ramsay et al.,

2007; Zvingilaite et al., 2008; Lobato et al., 2009; Van der Welle et al., 2009), concern the impact of RES-E on wholesale markets as well as the reaction by market participants; flexibility offered by generation units as well as deployment of demand response by loads. Furthermore, the design of generation support schemes is considered as a central issue.

3.3. Stages of network integration

Network integration concerns the integration of new RES-E generation units in both distribution and transmission networks. In total, five different stages of network integration have been identified. These vary from basic distribution networks with minor regulation that are operated very passively and configured towards centralized electricity generation (stage I), to very complex and smart networks with substantial regulation that considers all short and long term costs and benefits and that are operated in a very active manner (stage V). The phase classification is presented in Table 2.

Likewise the case of market integration, observing the penetration level of intermittent RES-E and regulatory and technical network characteristics in a specific country, one can derive the concomitant stage of network integration. Network integration issues that are likely to occur with the selected stage of network integration are shown in the following column. In order to mitigate or overcome the impact of these network integration issues on a cost-efficient integration of intermittent RES-E, institutional and technical response options are recommended to be implemented, as shown in the last column.

For example, a fairly high share of intermittent RES-E may increase network integration costs substantially when the 'fit-and-forget' network planning methodology is still in place, which implies that all possible network situations are resolved by ex-ante investments in additional hardware (new lines and cables, new transformers) for capacity extension. New innovative smart

⁴ Shares of intermittent RES-E below 10% are characterized as low; between 10% and 30% as fairly high and above 30% as high.

Table 2
Stages of network integration.

Stage	Description	Network integration issues	Recommendations
I Self-regulated networks	• Low RES-E penetration level • Active TN, passive DN • Negotiated network access • No incentives	• Negotiation on connection costs	• Negotiated third party access, negotiated connection charges
II Performance-based networks	• Low RES-E penetration level • Active TN, passive DN • Regulated network access • Incentives for efficiency improvements	• Negotiation on connection costs (especially grid reinforcements) • Limited congestion due to variable RES-E • Limited network reinforcements required for accommodating RES-E in DN	• Shallow regulated connection charges (mandatory access) • Basic congestion management • Reinforce distribution grids to accommodate small share of RES-E
III Enhanced performance-based networks	• Fairly high RES-E penetration level • Active TN, passive DN • Regulated network access • Incentives for efficiency, quality and basic innovation aspects	• Increasing network integration costs of RES-E (especially investments relieving congestion and allowing additional connection) • Differential DG impact across distribution networks not taken into account by network regulation • 'Fit-and-forget' network planning methodology increasingly inefficient	• Shallow regulated connection charges plus basic use of system charges for generators • Allow for paid curtailment of RES-E • Account for differential DG impact in network regulation • Demonstration projects about smart grids • Explicit innovation incentives for DSOs
IV Innovative networks	• Fairly high RES-E penetration level • Active TN, DN monitoring possibilities increase • Regulated network access • Incentives for efficiency, quality and innovation	• Further increase in network integration costs (upward flows from DN) • Network planning with deterministic reserve requirements increasingly inefficient • New network technologies render regulatory review of investment decisions more difficult • Increasing network congestion	• Proper incentives for generation/load by implementation of basic time differentiated network charges • Network planning with dynamic reserves • Network simulation tool for investment selection • Market-based congestion management
V Active networks	• High RES-E penetration level • Active TN, DN full monitoring and control possibilities • Regulated network access • Incentives for efficiency, quality and innovation	• Increasing network integration costs • Increasing network congestion • RES-E role in network management still limited	• Time and locational differentiated network charges • Smart meters increasingly deployed for network management • Wide application of active network management, DSOs are becoming entrepreneurs

grid technologies are able to free up network capacity at lower costs by involving grid users in real-time network management. Since the benefits of network innovations do not only accrue to the DSO, but also to other system actors, benefits of innovative measures are only partially included in the trade-off of network operators between deployment of innovative measures and conventional solutions. Hence, innovation by DSOs should be stimulated by network regulation.

Other central network integration issues, identified by extensive literature review (Lobato et al., 2009; Van der Welle et al., 2009) entail the manner in which costs of network planning and management are passed on to network users (i.e. network charging), and the procedure for allocating scarce network capacity by congestion management.

3.4. Regulatory road map tool

In the previous two sections we have presented two tables that deal with the two dimensions of system transformation process; the market and network integration phases of (intermittent) RES-E. Consequently, the next step is to bring those two dimensions together in one graphical scheme that combines the two tables. We refer to this scheme as the generic regulatory road map scheme. The basic scheme is depicted in Fig. 2.

The different stages of market integration are depicted on the horizontal axis. The horizontal axis at the same time also represents the impact of intermittent RES-E on the electricity system. This can be interpreted as either an amount of RES-E in the electricity system or the relative impact of existing RES-E. Based on the two axis we can depict (1) the current situation with respect to the amount/impact of RES-E in the current electricity system, (2) the current situation with respect to network integration in combination with the current level of market integration and (3) the likely end-state (i.e. future point in time, say 2020) of intermittent RES-E integration. The latter identifies the required level of network and market integration and is dependent on the likely system impact at the end of the time horizon. Within this figure, horizontal shifts represent a shift in the stage of market integration, whereas vertical shifts represent a shift in the stage of network integration. At a given current level of network integration it is possible that two bullets are inserted one to reflect the level of market integration and the other the actual amount/impact of intermittent RES-E on the other. In Fig. 2 it reflects that the current market integration level can successfully accommodate more intermittent RES-E without a change being required. When actual market integration is just sufficient to accommodate the associated level of intermittent RES-E, then one bullet represents the starting point of the road map. The movement from the initial starting point to the envisioned end (state) point is referred to as the regulatory road map.

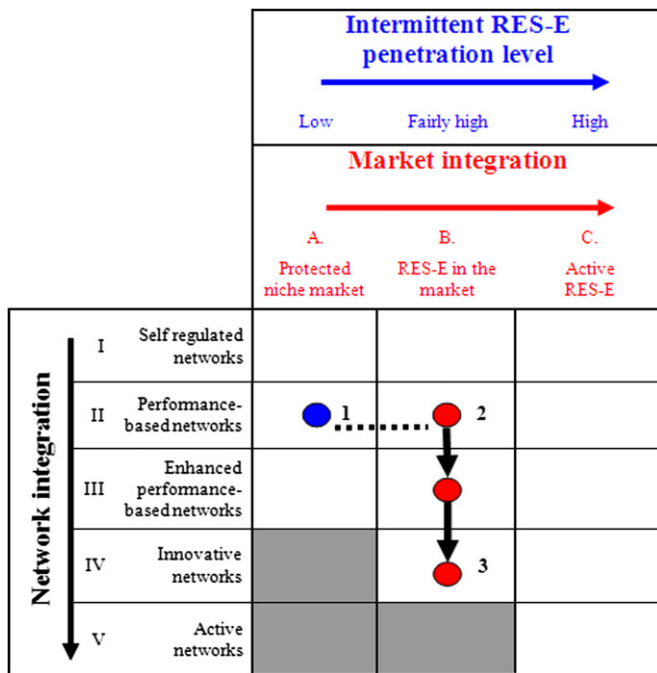


Fig. 2. Generic regulatory road map scheme.

Between starting and end point, intermediate points have been established, for two reasons. Firstly, step-by-step changes of regulation are deemed better than implementation of all kind of measures at once because of complexity and/or required regulatory coordination, technology development, investments, consumer participation, or preparatory actions for later phases. Secondly, a number of specific measures is linked to one of the less advanced market or network integration phases; not taking into account these recommendations implies that some extensive and costly measures are implemented, while more cost efficient measures are ignored. The latter is clearly detrimental to the integration of large amounts of RES-E. Apart from that, a part of the cells in the figure is marked gray, implying that at low levels/shares of RES-E there is no need for electricity systems to advance to the highest market or network integration stages to warrant the optimal integration of intermittent RES-E.

When applying this generic framework to a country such as The Netherlands it can be discussed what the optimal route concerning market and network regulatory actions is. This is dependent on country specific conditions i.e. system conditions. For example, a country that is well-interconnected with the other electricity systems abroad might be able to significantly increase its RES-E share in the country without having to alter existing network regulation (i.e. a move right-ward in the generic road map scheme).

4. Application of the regulatory road map scheme to The Netherlands

In this section we will apply the developed road map methodology derived in the former section to The Netherlands.⁵ The following basic questions will be answered for The Netherlands:

- What is the expected development of intermittent RES-E up to 2020?

⁵ For a number of other countries, Denmark, Germany, Spain and the United Kingdom, also road maps have been constructed; we refer to the full report on regulatory roadmaps (Van der Welle et al., 2009).

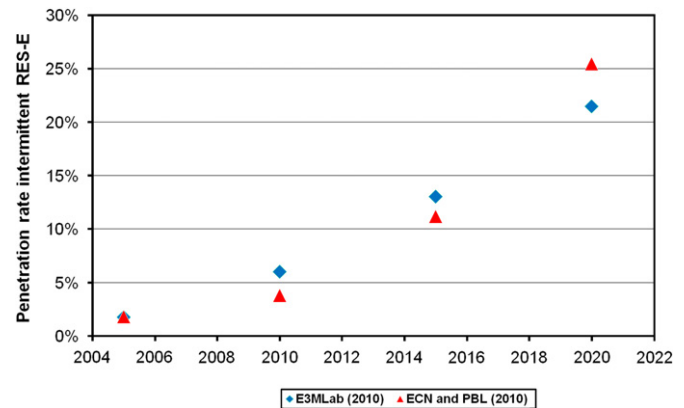


Fig. 3. Penetration rate of intermittent RES-E. (Calculations are based on production (GWh) figures. Penetration rate as percentage of final electricity consumption.)

- What is the associated required end-state of market and network integration?
- What is the current state of market and network integration?
- Which action points can be derived over time, and who should take responsibility?

4.1. Development of intermittent generation

Fig. 3 below shows the expected development of the penetration rate of intermittent RES-E (defined as onshore and offshore wind and photovoltaics) in time, according to both the PRIMES 2009 reference scenario (E3MLAB, 2010) and reference projections for The Netherlands (scenario 'determined and intended' policy, ECN and PBL, 2010). In 2020 the envisaged average penetration rate of intermittent RES-E is in the range of 20–25%. This estimate takes into account the renewable energy target, which has been adopted i.e. the EC target of 20% of final energy demand to be supplied by renewable energy. In the case of The Netherlands this means that about 35% of electricity has to be produced by *all* renewable generation. Onshore and offshore wind and to a minor extent PV will account for a large part of this additional required RES-E.

4.2. Required end-state of market and network integration

4.2.1. Market integration

Based on the projected developments in electricity production and the 2020 sustainability targets for The Netherlands we conclude that the likely level of intermittent RES-E in 2020 can be qualified as fairly high (i.e. between 10% and 30%).

Based on available studies (TenneT, 2005; Ummels et al., 2007), impacts on the balancing market seem relatively limited when reasonable assumptions for the forecast error are taken, given the fairly high amount of intermittent resources expected for 2020 in The Netherlands. Clearly, more sophisticated balancing integration studies would allow to substantiate this conclusion about balancing impacts further. Concerning electricity markets for longer time frames (intraday, day-ahead, forward markets); it is expected that they will exhibit substantially higher price variability.

Thus, the Netherlands predominantly faces the impacts related to the 'RES-E in the market' stage of market integration in 2020 (see Table 1):

- Fairly high penetration level of RES-E.
- RES-E has access to the balancing market and to the market for emergency power through Virtual Power Plants (VPPs). No access to other ancillary markets.

- RES-E is expected to have considerable effects on wholesale market prices and their variability.
- Increase of system balancing costs is probably relatively limited.
- Demand response is limited, mainly due to the lack of time-differentiated prices.
- The lack of negative prices at power exchange APX prevents production adjustments of intermittent generation.

Consequently, RES-E in the market (stage B) is the assumed market integration stage at the end-point.

4.2.2. Network integration

Expected impacts on the distribution and transmission networks in 2020 are substantial in terms of required additional network capacity due to more upward network flows from distribution to transmission network level and the generally larger distance between generation and load. More specifically, The Netherlands faces the following network-related impacts of intermittent renewable generation (see Table 2):

- In some regions, high wind and CHP shares in Westland, the Northern region and North-Holland North will increase further, exceeding load at many times and causing upward flows to transmission networks. Therefore, additional network reinforcements in transformers and new distribution and transmission lines are necessary, requiring large investments.
- Increasing unplanned electricity flows ('loop flows') at international interconnections with Germany diminish the availability of interconnection capacity for trading purposes and hence network utilization, resulting in more congestion. In order to counter this trend, better network planning based on probabilistic instead of deterministic reserve standards is required.
- Conventional 'hardware' solutions (new lines and cables) for more network capacity are impeded by social acceptance issues, sometimes necessitating burying of lines (Randstad 380+) or side-payments to regional government (maintaining and upgrading of 220 kV connection Zwolle-Eemshaven). Besides, efficiency notions ask for consideration of alternative network planning philosophies in the distribution networks.
- These innovative network philosophies however increase the number of available options for network investments, which makes it increasingly difficult for regulators like the Dutch regulator NMa/Energiekamer to review investment decisions as they do not dispose of a network simulation tool. This is likely to increase inefficiencies.

All in all, The Netherlands seems to face a number of network impacts, with associated fast increasing network integration costs of renewables. In order to limit the cost impacts for both (distributed) generators and consumers to the efficient costs, a transition to a more active and innovative type of network management is deemed necessary for The Netherlands ('more software instead of hardware') at the end-point of the roadmap (stage IV).

4.3. Current stage of market and network integration

Based on the following description on the current status of different issues relevant for the integration of RES-E in markets and networks, the current stages of market and network integration can be established.

4.3.1. Market integration

Since the actual market penetration of intermittent RES-E in The Netherlands is small one could conclude that the current

stage of market integration is stage A (protected niche market). However, when looking at the current market design and the actual opportunities of RES-E this corresponds more with an advanced stage of market integration (stage B) because of the following:

- A feed-in market premium support scheme already is in place.
- RES-E already provides some ancillary services through aggregators.
- Balancing market design is characterized by balancing responsible parties including RES-E, short gate closure time of day-ahead market, deployment of load for emergency situations through interruptible contracts and a country-wide organization.

This indicates that the Dutch electricity markets should be well capable to integrate fairly high levels of RES-E penetration without significantly altering current market design. Therefore one could conclude that the current stage of market integration in the roadmap corresponds to stage B (RES-E in the market).

4.3.2. Network integration

The transmission network in The Netherlands is increasingly deployed with steering and control possibilities like HVDC cables and phase shifters. However, the distribution networks are still managed by the 'fit-and-forget' philosophy, implying monitoring and control possibilities of network (actors) are highly limited. Network regulation is characterized by emphasis on achievement of short-term benefits, although incentives for quality regulation are implemented. However, explicit incentives for innovation are missing. We conclude that the current network integration stage is stage II (performance-based networks).

4.4. Regulatory road map for The Netherlands

Combining the end-points for both market and network integration sets the end-point in Fig. 4 below at stage IV-B in 2020. The same procedure sets the starting point at stage II-A/B in 2009. Consequently, the route from the initial starting point to the envisioned end point can be established. Mainly vertical shifts are

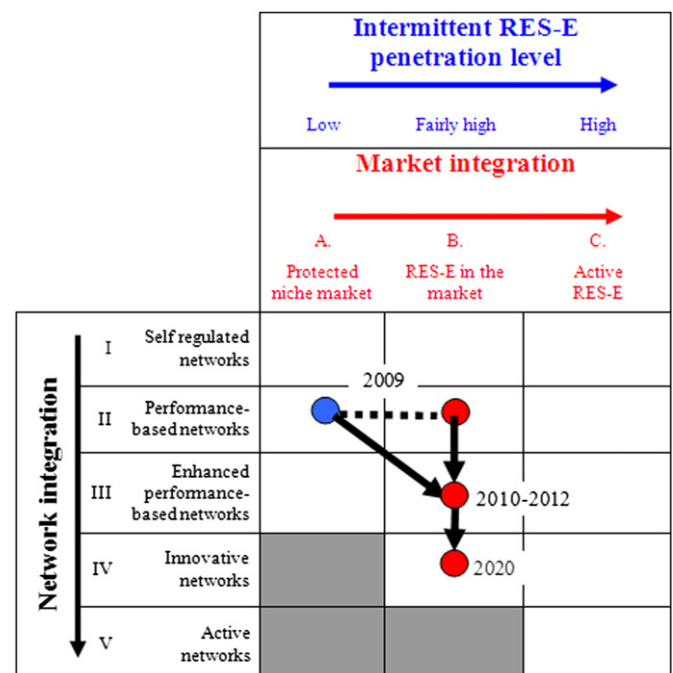


Fig. 4. Regulatory road map scheme The Netherlands: complete route 2009–2020.

Table 3
Action plan for The Netherlands.

Actor	2010–2012	2012–2020
Government	● Finalize standardization efforts for smart metering & develop common communication standard ● Allow for paid curtailment of RES-E during congestion ● One-stop shop approach for flexible generation	● Market-based national congestion management
Regulator	● Innovation incentives for DSOs ● Evaluate network planning standards	● Network planning with probabilistic standards ● Network simulation tool for network planning & investments
TSO	● Use-of-system charges for generators ● Possibilities for provision of ancillary services by RES-E	● Time-differentiated UoS charges ● Enable wider possibilities for provision of ancillary services by RES-E
DSOs	● Demonstration/pilot projects about smart grids and smart metering ● Demonstrate smart home area networks for advanced load control	● Introduce smart metering at premises of low voltage customers ● Implement smart home area networks for advanced load control ● Pilot projects for testing communication infrastructure for hourly/quarterly metering
Suppliers	● Introduce simple time-differentiated prices at wider scale	● Oblige time-differentiated prices
PX	● Allow possibility of negative prices at APX	

required in the regulatory roadmap, as the main recommendations concern improving network integration. Between starting and end point, one intermediate point has been established, for reasons explained in Section 3.4.

4.5. Regulatory action plan

With help of Tables 1 and 2 above the general recommendations coupled to the selected regulatory market and network phases can be derived. Besides, some country-specific measures are provided, which are tailored to the specific system conditions of The Netherlands. These recommendations should be considered as a package of measures, since measures in all system sectors i.e. generation, demand, networks and markets, are required for a cost-efficient integration of intermittent renewables in the system. In addition, a number of recommendations can be considered as mutual dependent (e.g. harnessing the benefits of smart metering for system integration requires the implementation of time-variable pricing for consumers). At the same time, some measures are more important than others; therefore only the most urgent and critical actions to improve system flexibility are shown in Table 3.

This Table also indicates the system actors who are first responsible for preparing, approving and implementing these sets of recommendations. Short-term actions are actions possible in the next years, while medium term actions due to complexity and/or required regulatory coordination, technology development, investments, consumer participation or preparatory actions only can be fully implemented after a couple of years, but well before 2020. Long-term actions should take place around 2020.

We focus on six of the most important actions to be taken in The Netherlands in the short to medium-term:

- Allow for paid curtailment of renewables in congestion management.
- Introduce explicit, output-based innovation incentives for DSOs.
- Apply network simulation tool for regulatory assessment of investment decisions.

- Evaluate network planning standards and implement probabilistic reserve requirements.
- Introduce the possibility of negative prices at power exchange APX.
- Reintroduce Use of System charges for generators.

4.5.1. Allow for paid curtailment of renewables in congestion management

Installing new conventional and RES generators may require reinforcing the grids, especially when new generation is located far away from load centers. Reinforcing the network usually takes more time than installing new plants, and starts only when generation consents have been provided. In order to provide new generators fast and full access even when network capacity falls short, Dutch network operators must connect new generation in the short term and manage abundant production through a new congestion management scheme. Renewable generators and high-efficiency CHP generators are exempted from the new congestion management system in order to guarantee priority access of renewable generators. Wind and other renewable energy sources are not allowed to be curtailed for market reasons. Although this policy may be preferable for maximum utilization of RES-E resources, from an overall system point of view this exemption comes at a price for two reasons.

First of all, since priority access prevents deployment of RES-E with often excellent ramping capabilities for congestion management, the legislation diminishes the flexibility of the power system, which will be reflected in higher congestion management and system costs. From a social welfare point of view, it is unlikely that the benefit of priority access i.e. higher RES-E production including its positive externalities, compensates for the increase in congestion management costs at all times. Besides, RES/DG cannot increase their revenues by diversification, limiting profits and consequently market integration of RES-E. Secondly, network congestion is likely to be exacerbated since renewable generators lack an incentive to take into account network congestion costs in their decisions whether to produce or not. This lack of cost reflectivity may increase the unevenness between

local supply and local demand for electricity even further, resulting in higher system costs.⁶

Consequently, for relieving the congestion against lowest social costs, we recommend that the government should not provide RES-E and CHP priority access, but allow them to be curtailed against a payment.

4.5.2. Introduce explicit, output-based innovation incentives for DSOs

Network innovation seems to be restricted by exclusion of positive external effects in investment evaluation by network operators; part of the benefits of network innovation will not accrue to the network operator but to other parties in the value chain (generators, suppliers, energy service companies, energy traders, etc.). Hence, although some innovative measures are likely to be beneficial for society as a whole, the benefits of innovative measures are only partially included in the trade-off of network operators between deployment of innovative measures and conventional solutions (Nieuwenhout et al., 2010). As a result, the demonstration and deployment of new technologies, for instance smart grid measures, is not taking place. Through implementation of network innovation incentives, this positive external effect can be incorporated in the network extension decisions of network operators. Network innovation incentives can be either input based mechanisms, which link a remuneration to the efforts of network operators or output based mechanisms, which link the remuneration to the results of those efforts i.e. ensuring an efficient and reliable energy supply. Preferably, network innovation incentives should be output based in order to leave the decision whether or not to invest in a specific technology completely to the network operators and other electricity system actors together. Such an incentive could be a distribution network capacity utilization factor, which provides an indication of the actual availability of network capacity for system actors with respect to a certain standard value. This indicator stimulates DSOs to freeing up as much as possible network capacity for generators, suppliers and other electricity system actors by deployment of innovative measures. Therefore, we suggest to implement explicit, output-based incentives in network regulation.

4.5.3. Apply network simulation tool for regulatory assessment of investment decisions

Under the current TOTEX regime, when large investments for network extension need to be done, the TSO/DSO has to submit an investment proposal to the regulator. The regulator has to assess whether investment proposals are substantial, exceptional and aim for either network extension or better network utilization, before costs can be added to the firms' cost base and remunerated accordingly. Nowadays, the technical assessment of investment proposals takes place by external technical experts (full results are not publicly available) and subsequently the regulator uses raw indicators to assess the value of investments on a case-by-case basis. Through the advent of smart grids new possibilities for network capacity extension at lower costs emerge like adding

intelligent network monitoring and controlling devices to the grid and active participation of generation and load. Benefits and costs of these new possibilities, including the potential contribution of RES-E, are difficult to monetise due to the large number of network conditions, which can differ across networks. Among others, factors like network topology choices made in the past (meshed or radial), network characteristics (in urban or rural area), DG penetration level and concentration all influence network performance. In this assessment deployment of a network simulation tool has a number of advantages. First, a network simulation tool can provide better insight in the value of different investment alternatives and new network technologies under different network conditions. In addition, the tool allows for a better coordination and optimization of network planning in time through for instance identifying upcoming bottlenecks with concomitant budget requirements. Furthermore, this tool facilitates interaction between utilities and the regulator and settling of related disputes between them (Jamasb and Pollitt, 2008). For all reasons, it is recommended that the Dutch regulator implements a network simulation tool. Since it takes time to develop such a tool this recommendation is intended for the medium term. Examples for such a tool can be taken from Spain and Sweden, among other countries.

4.5.4. Evaluate network planning standards and implement probabilistic reserve requirements

In network planning a number of standards are used in order to guarantee quality of supply. The maximum capacity of networks circuits is nowadays calculated using static (deterministic) assumptions with standard load profiles among others, implying reserve requirements are static as well (Zvingilaite et al., 2008). However, the increase in intermittent generation will make power flows more diverse and therefore standard requirements do not longer provide a good indication of required system reserves. When reserve requirements would depend on actual (real-time) wind and demand forecasts (i.e. are made probabilistic), additional network capacity becomes available in most time periods (Billinton and Allan, 1996). Moreover, network investments due to connection of additional renewable generation will be lowered without compromising security of supply. Therefore, the regulator (in cooperation with the TSO) should evaluate current deterministic network planning standards in the short term in order to consider replacement by probabilistic standards in the medium term.

4.5.5. Introduce the possibility of negative prices at power exchange APX

When there is abundant supply of power, day-ahead market prices will more frequently drop to zero. Sometimes the value of additional production may be even negative, but this is not reflected in the market price due to the lower limit of market prices of 0.01 €/MWh. Hence, generation sources with low marginal costs, typically renewable generators like wind turbines, which do not have fuel costs, will keep on producing electricity during all circumstances. This situation is further reinforced by the fact that RES-E receives production subsidy in addition to the market price. This may cause difficulties to the system as less flexible conventional generation may be not able to decrease its production fast enough during extreme system conditions.

The flexibility of the generation market can be improved by introducing the possibility of negative prices at power exchange APX to stimulate wind power to control their production during extreme system situations. Therefore, APX is advised to remove the lower limit to day-ahead market prices as soon as possible.

⁶ Apart from that, the effectiveness of the policy is also limited. Because wind generation comes first in the merit order of generation units, it disposes of the lowest marginal costs and will be only curtailed after conventional generators with higher marginal costs have done so. Wind generators will only offer to curtail their production if the revenues for relieving of congestion are higher than their opportunity costs i.e. the RES production subsidy. Because of the absence of fuel costs, deployment of wind generators is a more expensive option for TSOs than other generation and load options. Hence, wind generators will only be deployed for congestion management during extreme system conditions. Therefore, priority is often already obtained by market functioning, making the priority access regulation superfluous for wind generation.

4.5.6. Reintroduce use-of-system charges for generators

The integration of increasing amounts of RES-E gives rise to increasing costs in connecting users (i.e. generators and consumers) to the grid and costs for operation of the electricity system (i.e. transport and complementary system services). Connection costs are passed on to network users by connection charges, while the latter cost category, use-of-system costs, is passed on by use-of-system (UoS) charges.

Two distinct approaches of calculating connection charges can be distinguished: shallow and deep charging. Shallow connection charges include only the cost of connecting the customer to the nearest point in the network. The costs of additional network reinforcements are not included in these charges. As opposed to shallow connection charges, deep connection charges contain the costs of network reinforcements both at the transmission and distribution level as well as the direct connection costs. For providing fair and non-discriminatory network access to the network for different kinds of generators, including small RES-E units, The Netherlands has introduced shallow connection charges for all connection levels.⁷

However, at the same time the implementation of shallow connection charges is not a favorable option for system operators if the costs of network reinforcement for DSOs and TSO due to DG are not recovered in some way. Therefore, it is recommended to spread the incremental grid reinforcement cost among all network users through Use of System (UoS) charges (Van der Welle et al., 2009). Currently, UoS charges are entirely levied upon consumers in The Netherlands. Consequently, network reinforcement costs that the system incurs as a result of generator's decision to install a new plant at a certain location are not taken into account in investment decisions of generators. This is clearly inefficient from a system and welfare point of view and causes higher network integration costs than necessary. Reintroduction of cost-reflective use of system charges for generators (GUoS) is likely to resolve this inefficiency. In the past unilateral implementation of GUoS charges resulted in an uneven level playing field for Dutch generators across the EU, and forced the regulator to abolish these charges. Therefore, coordinated implementation of GUoS charges, at least at regional level but preferably at European level, is highly recommended.⁸

5. Conclusions and recommendations

This paper has shown in a qualitative fashion that future electricity systems will be faced with higher levels of variable electricity generation cumulating in higher power system costs if no system cost reducing options are implemented. For that reason, a large number of response options are presented in a still growing body of literature, varying in nature and cost-effectiveness. For example, the available interconnection capacity for trading can be increased, smart metering and hourly pricing can be implemented for enlarging demand response, (additional)

⁷ This avoids large upfront costs for RES-E, which would discriminate against DG as compared to centralized generation. Besides, this kind of connection charges lowers transaction costs to DG by keeping the calculation straightforward and transparent and avoiding negotiations about the “deep” connection cost component.

⁸ As the value of network transport depends heavily on the location and timing of production, introduction of UoS charges differentiated to location and time should be considered. In that case, generators are stimulated to locate nearby load and actual production is stimulated to be in accordance with local or regional demand. Locational UoS charges are also in line with provisions in Regulation (EC) No. 714/2009 (European Council, 2009). They are also widely supported by literature; see for instance Jamasb et al. (2005) and, for the case of The Netherlands, Niesten (2010).

storage facilities can be incentivised, and DSOs can be made subject to innovation incentives in order to consider smart grids as an alternative for conventional network reinforcements. However, for policy makers it is general unclear which (combination of) option(s) is most feasible, when the option(s) should be implemented and how the different options are linked to each other. Therefore, in this paper the regulatory roadmap methodology was set out in a qualitative fashion for The Netherlands to set an example. When applying this methodology policy makers are able to analyze systematically the national need for better RES integration in markets and networks, and therefore to choose systematically the most appropriate combinations of institutional and technical response options in time. This approach can and in fact has already been successfully applied to a number of countries in the RESPOND project.

The key advantage of designing regulatory roadmaps is that it warrants a systematic and integrative approach to the prioritization and timing of prospective regulatory reforms. Reforms deemed necessary in The Netherlands include the following:

- Allow for paid curtailment of renewables in congestion management.
- Introduce explicit, output-based innovation incentives for DSOs.
- Apply network simulation tool for regulatory assessment of investment decisions.
- Evaluate network planning standards and implement probabilistic reserve requirements.
- Introduce the possibility of negative prices at power exchange APX.
- Reintroduce Use of System charges (i.e. grid tariffs) for generators.

Finally, on an EU or national level this analysis can be further underpinned by quantitative cost–benefit analysis and other quantitative modeling approaches of the measures proposed for a specific system. The actual added costs and benefits are dependent on many country-specific conditions such as market structure, geographical conditions and prevailing regulation. Such analysis would give further insight in the prioritization of regulatory actions over time. Whereas the prioritization and timing of regulatory actions in this study could only be highlighted indicatively, quantification-based recommended actions could give rise to more definite priorities and timing. This remains a challenge for future research.

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