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Morocco's sustainable energy transition and the role of financing costs: a participatory electricity system modeling approach

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Abstract

Background: Morocco is facing major challenges in terms of its future energy supply and demand. Specifically, the country is confronted with rising electricity demand, which in turn will lead to higher fossil fuel import dependency and carbon emissions. Recognizing these challenges, Morocco has set ambitious targets for the deployment of renewable energy sources for electricity generation (RES-E). The realization of these targets will lead to a fundamental transition of the Moroccan electricity sector and requires substantial public and private investment. However, different risks constitute barriers for private RES-E investments and lead to high financing costs, which may eventually discourage capital-intensive RES-E projects.

Methodology: While the existing literature has mainly focused on assessing the impact of financing costs on the economic competitiveness of individual technologies, the aim of this research is to assess the techno-economic feasibility of different electricity generation portfolios. To recognize the social dimension of the sustainable energy system transition, the electricity scenarios for Morocco have been jointly developed with stakeholders in a scenario building workshop in Rabat, employing a downscaled version of the open source electricity market model renpassG!S, augmented by a weighted average cost of capital (WACC) module.

Results: In the stakeholder workshop, four different electricity scenarios for Morocco were co-developed. Each of these scenarios describes a consensual and technologically feasible future development path for the Moroccan energy system up to 2050, and comprises conventional fossil fuel-based technologies, as well as RES-E technologies in varying shares. Employing the downscaled renpassG!S model, we find that total system costs, as well as average levelized costs of electricity (LCOE) can be reduced substantially with low-cost financing.

Conclusions: Our results indicate that de-risking RES-E investments can lead to cost competitiveness of a 100% RES-E-based electricity system with mixed-technology scenarios at marked financing costs. Therefore, we identify specific de-risking recommendations for Moroccan energy policymaking. In addition, we argue that participatory scenario modeling enables a better understanding of the risk perceptions of stakeholders, and can eventually contribute to increasing the political feasibility of sustainable energy transition pathways.

Keywords: Renewable electricity, Participatory modeling, Risk perception, Investment barriers, De-risking, Morocco

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Background

Similar to many other African countries [1–4], Morocco is facing major challenges regarding the future of its energy system [5], particularly in terms of the electricity sector [6]. The Moroccan policymaking process is confronted with substantial increases in electricity demand, with growth rates estimated to be twice as high as in the North Mediterranean area due to population growth and advances in socioeconomic development [5, 6]. It is estimated that the annual electricity demand could rise from 35 TWh in 2016 to either 80 TWh (historical data extrapolation), 115 TWh (national outlook), or 170 TWh (model based estimate) by 2050 [7]. This will require the deployment of additional electricity generation capacities with volumes four times higher by 2030 and more than ten times higher by 2050 [7, 8]. Given the high intensity of fossil fuel use in Morocco's current electricity generation portfolio, increasing electricity demand will also lead to higher fossil fuel import dependency, as well as to increasing levels of electricity-related carbon emissions [9]. Moreover, global warming due to anthropogenic climate change will drive cooling electricity demand up and potential impacts of climate change on the energy infrastructure might be large. All these potential future developments require a substantial reconsideration of Morocco's energy policy.

As a result, an ambitious target was set for further deployment of renewable energy sources in the electricity sector (RES-E). This target foresees high penetration rates of RES-E, namely 42% of total generation capacity by 2020, and 52% by 2030 [10]. As 1 of 40 member nations of the Climate Vulnerable Forum, Morocco jointly declared the goal of reaching 100% RES-E supply between 2030 and 2050 [11]. These targets will require an additional deployment of roughly 10 GW of RES-E capacities by 2030. From those, 4.6 GW is foreseen to come from solar, 4.2 GW from wind, and 1.1 GW from hydro.

This kind of transition in the electricity sector requires substantial levels of investment—estimated at on average USD 1 trillion per year until 2050 at the global level [12, 13]. According to the Moroccan Ministry of Energy, Mines, Water, and Environment, roughly USD 30 billion in investment will be needed to fund the deployment of RES [14]. The challenge for Morocco now lies in diverting current investments from conventional high-carbon technologies to low-carbon ones, and in raising additional financial resources for operationalizing the RES-E transition, given the anticipated increases in electricity demand. In developing countries in general, there is a gap of up to 8% of GDP, which is needed to support energy infrastructure deployment. Hence, for the deployment of RES-E, involvement of private capital is crucial [15].

The volumes of public spending requirements for infrastructure investments, such as renewable energy, are increasing globally. Public financial actors have in fact drastically increased their share of RES investments in total investment over time, particularly in high-risk technologies [16]. The deployment of RES-E at scale, which is necessary to reach the ambitious RES-E targets in Morocco and other contexts, will therefore require more extensive involvement of supplementary financing sources in addition to state finance, such as from private sources, international financial institutions, and multilateral development banks (MDBs). Particularly capital-intensive investments such as large-scale concentrated solar power (CSP) will require significant participation of private capital. According to the International Energy Agency (IEA)'s new policy scenario [12], non-OECD (Organization for Economic Co-operation and Development) countries annually have to invest on average USD 1200 billion in energy supply infrastructure. That leaves a financing gap of almost USD 500 billion compared to the historical investments of USD 708 billion. Taking into consideration existing development goals and related expenditures, the public sector alone will not be able to raise all of the required capital. In Europe, there is already a tendency to involve private capital in the provision of services, which were traditionally regarded as pure public goods.

While Morocco is situated in one of the world's most favorable regions for the generation of solar and wind electricity, significant investment barriers that jeopardize RES-E development at scale still prevail [17–20]. Different investment risk profiles and risk perceptions across countries and technologies lead to differences in financing costs for individual technologies, which eventually lead to different generation costs [21]. Investors' risk perceptions are particularly high for RES-E technologies [22]—which are characterized by high capital expenditures (CapEx)—and for developing countries [23]. This could lead to relatively high generation costs for some RES-E technologies (e.g., CSP) when compared to conventional technologies [9] and may eventually discourage capital intensive RES-E investments at scale [24].

The existing literature mainly focuses on single technology assessments with regard to the effects of differences in investment risks and financing costs [25–33]. While these studies shed light on context-specific details that may lead to variations in financing costs across different technologies and regions, we suggest a more comprehensive approach when assessing the role of financing costs for a fundamental transformation of the electricity system. To effectively support planning in energy policy, an interlinked electricity system of various generation technologies, each characterized by its own financing cost and risk profile, has to be assessed. Such an integrated approach is needed as the comparison of individual technologies' levelized cost of electricity

(LCOE) is not sufficient: The *capacity value* or *system value* of power generation technologies is also important, if not even more so [34–37]. This value may vary for electricity produced by different technologies, between locations, and from one hour to the next. Hence, the benefit of such an integrated assessment is to show what role individual technologies may play in future electricity generation portfolios, while ensuring that these future scenarios are technologically as well as economically feasible. Moreover, this comprehensive electricity systems approach allows for the identification of technologies characterized by high financing costs and investment barriers, and should therefore be at the center of attention of national energy policymaking. Most model-based assessments that consider the whole electricity system do not consider variations in financing costs explicitly [38–41]. One exemption is the application of the numerical electricity market model EMMA to evaluate the impact of capital costs and carbon prices on the deployment of RES-E and other low-carbon technologies [24].

We build on, and move beyond the current state of the literature and assess comprehensive electricity scenarios for the case of Morocco. Moreover, to recognize the social dimension of sustainable energy system transitions, these scenarios have been co-developed in a stakeholder process and assessed by employing a comprehensive electricity sector model—renpassG!S—tailored to the Moroccan case and downscaled to be used in a participatory setting. While other research on future power systems often focuses on energy scenarios based on full-cost cost-optimization [24] or political and expert-based long-term targets, the approach taken in this article puts emphasis on the inclusion of the views and estimates of diverse societal stakeholder groups and their expectations for Morocco's future power system [42]. More precisely, we set out to answer the following research questions: How do socially accepted and techno-economically feasible future electricity scenarios, co-designed in a participatory process and characterized by different portfolios of electricity generation technologies, look like for Morocco? What is the impact of different financing costs (due to different risk profiles of technologies, different financing sources, and regional specifics) on the average LCOE and in turn on the economic feasibility for these co-designed electricity scenarios?

Morocco's current electricity system and its energy transition plans

Back in the 1990s, Morocco launched an electricity program that aimed to ensure access to electricity for rural households. Moreover, a controlled liberalization of the country's electricity generation was initiated with the signing of the first Power Purchase Agreements (PPAs) with independent power producers. The demand for electricity almost tripled from 13.265 TWh in 1999 to 35.405 TWh in 2016 [43]. Further, access to electricity in rural areas increased from 18% in 1995 to 99.42% in 2016 [43]. The installed power mix in Morocco as of 2016 is presented in Table 1 [43].

Currently, Morocco is relying on the development of RES-E power plants to meet the rising electricity demand and to achieve the energy shift as framed in the energy strategy launched in 2009 [44]. The strategy covers five areas:

- Establishing an optimized fuel mix in the power sector
- Increasing deployment of RES technologies in power generation
- Promoting private investments in the power sector
- Promoting energy saving and use efficiency in the industrial, commercial, and residential sectors
- Promoting regional power grid integration.

According to this strategy, Morocco will have the following installed power mix [43]:

- By 2020, the installed capacity will reach 13,320 MW of which 48% will be RES-E based

Table 1 Electricity generation mix in Morocco

	Installed capacity in MW	Shares of total installed mix in %
Hydropower	1770	22
Steam thermal power plants	1065	13
Gas turbines	1230	15
Diesel groups	201	2
Coal thermal power plants JL	2080	25
Gas turbine combined cycle	836	10
Wind power plants	892	11
Solar	181	2
Total	8255	100

(2000 MW solar, 2500 MW wind, and 1820 MW hydropower)

- By 2030, the installed capacity will reach 21,200 MW, of which 52% will be RES-E based (4000 MW solar, 4000 MW wind, and 3100 MW hydro, including pumping stations).

Morocco is considering the development of marine pumping stations in order to back up the intermittent RES-E systems. In addition, the country is developing a USD 4.6 billion liquefied natural gas program in order to back up the intermittency of solar and wind energy power plants.

In order to establish effective financing mechanisms for fostering RES deployment in Morocco, the GoM established the “société d’investissements énergétiques (SIE)” in 2010. The SIE was designed as a public financial instrument in order to support and enable investments in RES projects by taking minor stakes in specific projects. Capitalized with approximately EUR 100 million, the GoM targets to leverage private national and international financial resources to invest in RES projects in Morocco.

In parallel, the GoM established in 2009 the “Fonds pour le développement énergétique” with a total capitalization of 1 Billion US$ to implement the national energy strategy. The fund was established by the annual financial law 2009 [45] and designed to assure investment in strategically important public RES projects.

Within the private financial sector, Moroccan Banks have been able to leverage optimized financing of EUR 1 billion per year to finance energy projects in the country [46]. The Moroccan banks join efforts within an instrument of Local Banks syndication.

The role of investment risk in decarbonizing the electricity sector

Different investment risks—both objective and subjective—can lead to an increase in financing costs for infrastructure investments. Due to the high capital intensity of low-carbon RES-E technologies, high capital costs have a stronger impact on the economic feasibility of specific RES-E investments than on conventional fossil-based investment projects. Thus, high capital costs, sometimes expressed as high WACC [25, 27], lead to a strong increase in the LCOE from RES-E and therefore tend to discourage RES-E investments at scale. Financing costs for capital-intensive RES projects [22] are found to be particularly high in developing countries [23].

Objective financial risks include operational, revenue, liquidity, financing, and foreign investment risks [47, 48]. Operating risk is defined as the risk of loss resulting from inadequate or failed internal processes, people, and systems, or from external events (Basel II). Liquidity risk occurs when an asset cannot be sold on the market quickly enough to minimize a loss due to a lack of potential buyers or an inefficient market. Financing risk includes the availability of financing and its costs, as well as inflation and foreign exchange rates. Foreign investment risk includes the risks of rapid and extreme changes in value due to smaller markets; differing accounting, reporting, or auditing standards; nationalization, expropriation, or confiscatory taxation; economic conflict; or political or diplomatic changes. Valuation, liquidity, and regulatory issues may also add to foreign investment risk [49–52].

Apart from objective risks, there are also subjective risks connected to perceived barriers to project realization. The risk perception of a stakeholder is a combination of the perceived likelihood of the occurrence of a negative event and its associated impact. The risk perceptions are also closely connected with how much risk people are willing to accept [53], and with their decision on whether to invest in a certain technology or not [54]. In economic theory, such behavior is known as risk aversion, which is a feature of economic behavior when foreign direct investment (FDI) investors are hoping to minimize risk. It can mean that even if a given investment promises benefits, investors will stay away when the possibility of losing money is too large [55]. Risk perceptions also impact WACC, LCOE, and the delay cost parity of solar with fossil fuels, and lead to greater investment requirements [22]. According to research published by Schmidt [21], risk perceptions matter more for private RES-E investments than for private investments into fossil fuel-based electricity generation technologies.

To foster private RES-E investments alongside public ones, investors require support in terms of financing and risk sharing. The involvement of MDBs can contribute to the reduction of investment risks associated with financing, uncertainty about returns, and potential financial losses. In addition, the involvement of MDBs can further contribute to the reduction of subjective risks associated with investments into RES-E, which are connected to perceived barriers to project realization, and hence contribute to the so-called *de-risking* approach [9, 22]. From the involvement of MDBs, private RES-E investors expect the following possibilities to reduce investment risks: competitive pricing, a favorable time and cost of bidding, an attractive internal rate of return, bankability, value for money, the lowest level of equity possible, debt sizing, and more generally, the sharing of risks through all project stages [28]. Despite the important role MDBs might play in the dissemination of new RES-E technologies to the global South, there is only very limited research available on this topic. A recent bottom-up analysis of MDB project data finds first indications that both global and regional MDBs are indeed getting more heavily involved in financing RES-E projects in developing countries [56].

Methods

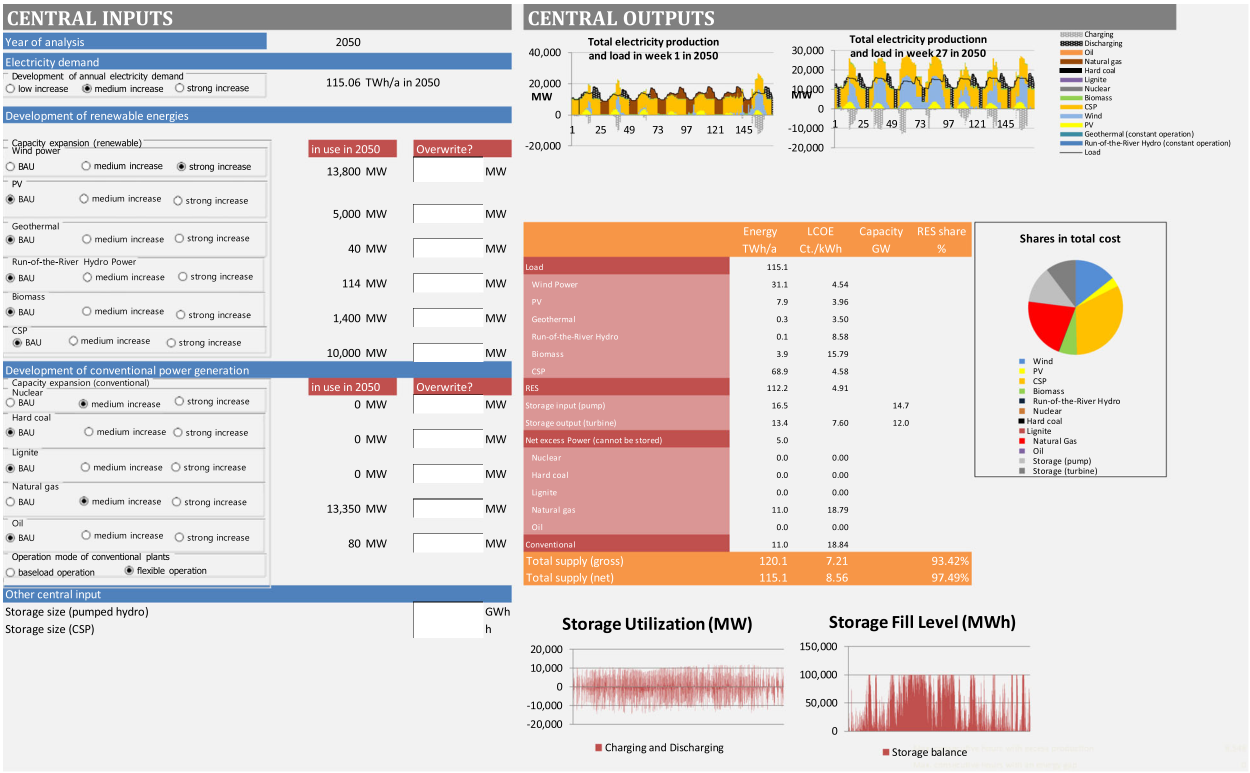
Our methodological approach reflects a case study analysis of low-carbon electricity pathways for Morocco, employing qualitative social science methods and quantitative techno-economic modeling tools. While other research activities on future power systems often focus on energy scenarios based on full-cost-optimization or long-term targets, the approach taken in this article puts emphasis on the inclusion of the views and estimates of diverse societal stakeholder groups about their anticipation of Morocco's future power system. This approach was key to gaining a broad spectrum of potential future developments that have a high level of stakeholder buy-in. The researchers' role was limited to providing the tools, and moderating and guiding the scenario development process [42].

Stakeholder workshop: co-generation of electricity pathways

The workshop was organized by MENARES (Middle East North Africa Renewables and Sustainability) in cooperation with the International Institute for Applied Systems Analysis (IIASA), Europa-Universität Flensburg, and the Wuppertal Institute in Rabat, Morocco, in May 2016. The aim of the workshop was to develop consistent scenarios of Morocco's power system until 2050 in collaboration with Moroccan stakeholders. The workshop also provided a platform for intensive discussion between different stakeholder groups on the technical, economic, and social aspects of different scenario settings. It included 25 participants from the public and the private sector, as well as academia and civil society. Among them were the leading national ministries and electricity companies, as well as governance organizations at the regional and national levels, private companies working in the RES-E sector, major Moroccan universities, and environmental and young civil society organizations [42].

Downscaled open access renpasG!S model

A downscaled spreadsheet version of the open source energy system simulation software renpassG!S[1] [57–60] was developed and employed for the co-development and assessment of the power supply scenarios in the stakeholder workshops in Morocco (Fig. 1 shows the central input and output spreadsheet interface). Simulations with the full renpassG!S model would have



CENTRAL INPUTS

Year of analysis 2050

Electricity demand

Development of annual electricity demand
○ low increase ● medium increase ○ strong increase
115.06 TWh/a in 2050

Development of renewable energies

Capacity expansion (renewable) | in use in 2050 | Overwrite?

Wind power
○ BAU ○ medium increase ● strong increase
13,800 MW ☐ MW

PV
● BAU ○ medium increase ○ strong increase
5,000 MW ☐ MW

Geothermal
● BAU ○ medium increase ○ strong increase
40 MW ☐ MW

Run-of-the-River Hydro Power
● BAU ○ medium increase ○ strong increase
114 MW ☐ MW

Biomass
● BAU ○ medium increase ○ strong increase
1,400 MW ☐ MW

CSP
● BAU ○ medium increase ○ strong increase
10,000 MW ☐ MW

Development of conventional power generation

Capacity expansion (conventional) | in use in 2050 | Overwrite?

Nuclear
○ BAU ● medium increase ○ strong increase
0 MW ☐ MW

Hard coal
● BAU ○ medium increase ○ strong increase
0 MW ☐ MW

Lignite
● BAU ○ medium increase ○ strong increase
0 MW ☐ MW

Natural gas
○ BAU ● medium increase ○ strong increase
13,350 MW ☐ MW

Oil
● BAU ○ medium increase ○ strong increase
80 MW ☐ MW

Operation mode of conventional plants
○ baseload operation ● flexible operation

Other central input

Storage size (pumped hydro) ☐ GWh

Storage size (CSP) ☐ h

CENTRAL OUTPUTS

	Energy TWh/a	LCOE Ct./kWh	Capacity GW	RES share %
Load	115.1			
Wind Power	31.1	4.54		
PV	7.9	3.96		
Geothermal	0.3	3.50		
Run-of-the-River Hydro	0.1	8.58		
Biomass	3.9	15.79		
CSP	68.9	4.58		
RES	112.2	4.91		
Storage input (pump)	16.5		14.7	
Storage output (turbine)	13.4	7.60	12.0	
Net excess Power (cannot be stored)	5.0			
Nuclear	0.0	0.00		
Hard coal	0.0	0.00		
Lignite	0.0	0.00		
Natural gas	11.0	18.79		
Oil	0.0	0.00		
Conventional	11.0	18.84		
Total supply (gross)	120.1	7.21		93.42%
Total supply (net)	115.1	8.56		97.49%

Fig. 1 The central input and output spreadsheet interface of the downscaled renpassG!S model employed in the participatory modeling workshop in Morocco

required long computation times, which was regarded to be infeasible for the workshop schedule. The full model was consequently downscaled to a simplified spreadsheet model that allowed shorter response times and an instant display of results. It incorporated the full model's main functionalities, but was less flexible in terms of the merit order of dispatchable technologies.[2] The renpassG!S model was selected for this modeling exercise because it is a freely available, open source model that can fairly easily be adjusted to the user's requirements [61]. This was advantageous as another aim of the research leading to this article was to provide an open access tool for participatory electricity system planning for developing countries.

The basic structure of the renpassG!S model (depicted in Fig. 2) is as follows. Scenarios of a country or region's power supply are optimized within the model. An hourly resolved load curve is covered by the electricity production from pre-defined capacities of different kinds of power generating technologies. A solver that approaches the numerical partial equilibrium [62] is utilized for the optimization, and thus the least-cost mode of operation of the entire system. Due to their marginal cost close to zero [63], non-regulated RES-E, such as photovoltaic, solar, and wind power, will therefore operate whenever meteorological conditions are suitable. Dispatchable technologies will come into operation according to the ascending order of their marginal cost. The model allows the simulation of electricity production from RES-E and dispatchable production in a high spatial and temporal resolution. The main model outputs are hourly resolved production figures of all pre-defined components of the simulated energy system that are subsequently used as inputs into further post-processing procedures such as the calculation of LCOE and resulting CO_2 emissions.

In the application of the downscaled model, Morocco was split into four regions. For each region, a load curve (based on [43]) and meteorological data in an hourly resolution (derived from [64] and further processed) were utilized. The latter were translated into region-specific normalized production curves of RES-E wind power, photovoltaic solar power, and CSP. Combined with the installed capacity as defined by the workshop participants, RES-E production curves were generated in the model. The underlying load curve was scaled according to the expected load level in 2050 [65]. The residual load was derived by subtracting the power production from RES-E from the load curve. It was subsequently covered by dispatchable generation based on the available capacity as defined by the workshop participants and the merit order of the technologies [42]. In case of power shortages, additional production or storage capacity had to be added to the system by the workshop participants.

By relating the existing transmission lines between the defined regions and the modeled consumption and production for the four grid regions in the year 2050, the model takes potentially necessary enhancements of the national transmission grid infrastructure into account. Due to the complexity of the subject and the aim to develop the scenarios during a workshop session, in this approach Morocco was contemplated as an isolated system, that is, without transmission links to neighboring countries. Any consistent scenario of such a system will also work in an interlinked system [65].

For the financial risk analysis, an additional module was developed and added to the downscaled spreadsheet version of the renpassG!S model, allowing a greater variation of key financing parameters such as the shares of equity and debt capital, and the respective interest rates.

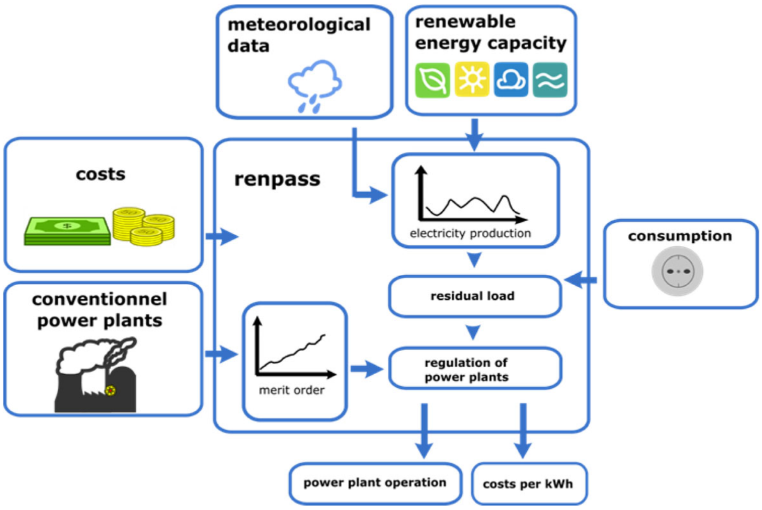


Fig. 2 Basic structure of the renpassG!S model. Source: Berg et al. (2016)

In this WACC module, average interest rates were calculated for every technology in the system and fed into the calculation of LCOE of all technologies and the overall system as key outputs of the modeling exercise. In the calculation of the WACC, the equity rate of return i_{En} and the debt interest rate i_{Dn} applicable for a certain power generation technology in Morocco (see details on data employed in the following section) are weighted by their respective shares in the overall external funding of the project (see [25] for more details).

$$\mathrm{WACC}_n = i_{En}\left(\frac{E_n}{E_n + D_n}\right) + i_{Dn}\left(\frac{D_n}{E_n + D_n}\right)$$

WACC_n…Weighted average cost of capital for technology n (in percent)

i_{En}…Equity rate of return for technology n (in percent)

E_n…Share of equity used in investment project for technology n (in percent)

i_{Dn}…Debt interest rate for technology n (in percent)

D_n…Share of debt used in investment project for technology n (in percent)

Data

Technical input data for renpassG!S

For the calculations, Morocco was split into four GIS-based regions as shown in Fig. 3, depending on differences in the wind and solar power potential, as well as on the existing transmission grid infrastructure (calculations based on [64, 66, 67] and own assumptions). Specific input parameters, such as meteorological data and the level of demand, were considered region-specific. For each region, one representative metering point for meteorological data was chosen. In the model, all installed capacity was distributed to the four regions, depending on area availability and expert judgment gained during the workshop (RES-E), as well as the existing installation (conventional generation).

Key inputs to the model were technical and meteorological data, accompanied by geographical data. On the technical side, the production capacities of all technologies in the system were included as defined by the workshop participants. In the model, the RES-E capacities were linked to normalized production curves of the respective technologies, based on recorded meteorological data such as wind speeds and solar radiation found in [64] and further processed with [67], as well as with a representative wind power production curve.

The annual load curve was based on ONEE (2017) and our own calculations. Its regional breakdown was based on the size of the region and population density. The level of power demand in 2050 was defined by the workshop participants and is based on estimates by [65] and other stakeholders. The workshop consensus reached was that demand will be strongly increasing to 173 TWh/a by 2050, which corresponds to an increase by a factor of approx. five, compared to Morocco's electricity demand in 2016.

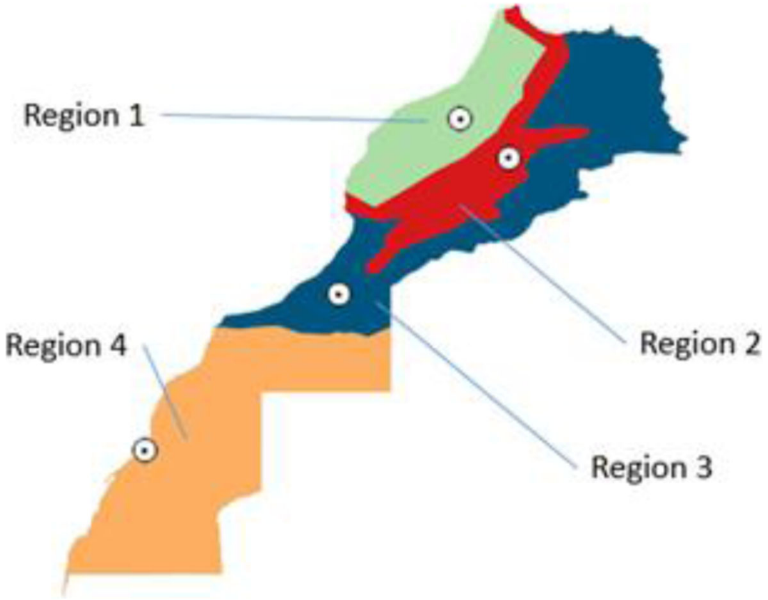


Fig. 3 Morocco's four climatic regions. Source: own visualization based on NASA (2016), NREL (2010) and ONEE (2017), and own calculations

For fuel-based power plants, further technical parameters, such as ramping and minimum down times and efficiencies, were taken into consideration in the model. Moreover, emissions coefficients were included in order to calculate required fuel inputs and resulting direct CO_2 emissions.

The net transfer capacity between the defined regions was calculated based on Bohm et al. (2011) and ONEE (2017), complemented by an estimated length of the transmission lines.

Economic input data for renpassG!S

The economic parameters in the model comprised specific investment costs, as well as the variable cost of all technologies in the system. Variable cost in the model included operational expenditure for starting and ramping-down of power plants, and for plant operation in general, as well as fuel and CO_2 costs. The cost parameters were derived from various sources [68–72].

For the economic parameters in the model, a development until 2050 that translates into investment cost reductions for most of the technologies was taken into account. The investment costs were discounted to enable operation with annual cost figures. The investment costs relevant in the year of analysis (2050), thus also included costs for investments made in the years before.

For the calculation, we used detailed financing cost information for individual RES-E technologies based on real-world data from investment projects in Morocco. We employed standard market-based capital cost rates (equity rate of return ranging from 15 to 18% depending on the technology and debt interest rate ranging from 5 to 7% depending on the technology), and equity/debt shares (20% equity and 80% debt financing) for the base run. For the sensitivity analysis, we used detailed financing cost information for individual RES-E technologies, based on real-world data from public investment projects in Morocco, characterized by very favorable financing conditions due to the involvement of development banks (Table 4 in the Appendix).[3]

Results

Participatory scenario generation

In the May 2016 stakeholder workshop in Rabat, Morocco, four different electricity scenarios for Morocco were jointly developed. Each of these scenarios describes a consensual and technologically feasible set of power generation and storage capacities in the year 2050 that would cover the power demand in every hour of the year (which is assumed to be the same 173 TWh/a for each scenario), accompanied by a future development path for the Moroccan energy system up to 2050. Each scenario comprises conventional fossil fuel-based technologies as well as RES-E technologies in varying shares (see Table 2):

Scenario 1 (S1): Characterized by a mix of RES-E and conventional technologies (e.g., wind + solar PV = 50 GW).
Scenario 2 (S2): Characterized by a mix of production capacities that result in a fully RES-E-based power supply (e.g., wind + solar PV = 75 GW).
Scenario 3 (S3): Characterized by a mix of production capacities with a strong focus on solar PV (two-thirds of the installed capacity).
Scenario 4 (S4): Characterized by a mix of RES-E and conventional technologies. Similar to S1, but with different technology shares and a substantially greater capacity of gas-fired power plants.

A common feature of all scenarios is the absence of nuclear power generation. This reflects a consensus decision by this workshop's participants but should not imply that nuclear power is not being discussed at all in Morocco as a potential future electricity generation technology. Even though a direct comparison of the scenarios is possible only to a limited extent, it highlights the variety of potential future system settings and provides relevant insights for electricity system planning and policymaking. Table 2 points out that electricity production levels are in the same range. Production capacities, however, necessarily have to be different between the scenarios according to the respective generation technology mix across scenarios 1, 3, and 4 (185 TWh, 184 TWh, and 189 TWh, respectively), with the only exception being scenario 2 (205 TWh). This is due to the fact that scenario 2, the 100% RES-E scenario, has the highest share of intermittent production, which to a certain degree cannot be stored or utilized throughout the year and hence is lost.

For each of the four electricity scenarios, we investigated the following two financing cost scenarios, based on RES-E project-specific data (see Table 4 in the Appendix):

(1) Best-case scenario, where commercial banks finance RES projects (solar, wind, hydro) with involvement of development banks.
(2) Market scenario, where commercial banks finance RES projects (solar, wind, hydro) without involvement of development banks.

Table 2 Four electricity scenarios for 2050 co-developed in a stakeholder workshop

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
	Capacity [MW]	Production [TWh]	Capacity [MW]	Production [TWh]	Capacity [MW]	Production [TWh]	Capacity [MW]	Production [TWh]
Technologies								
Wind	35,000	111	45,000	142	10,000	32	40,000	126
Solar PV	15,000	23	30,000	45	50,000	75	10,000	15
Reservoir hydro	3100	0	3100	0	3100	0	3100	0
Biomass	3000	18	5000	16	0	0	3000	16
CSP	2000	4	2000	2	1300	3	1500	2
Hard coal	5000	20	0	0	4937	35	6000	21
Oil	741	2	0	0	741	4	741	1
Natural gas	5500	9	0	0	6172	35	6172	7
Nuclear	0	0	0	0	0	0	0	0
Total	69,341	185	85,100	205	76,250	184	70,513	189
Pumped-hydro storage								
Capacity [GWh]	702		2000		2000		702	
Pump capacity [GW]	9.0		10.0		10.0		8.1	
Turbine capacity [GW]	7.3		16.0		12.9		5.9	
Thereof (in %)…[a]								
Intermittent	65%	71%	74%	93%	67%	58%	66%	74%
Partially variable	7%	3%	5%	1%	5%	4%	6%	3%
Variable	28%	26%	21%	13%	28%	47%	28%	24%
Renewables	76%	84%	84%	102%	72%	62%	76%	85%

[a] Percentage of total producing capacity including pumped-hydro energy storage

Table 3 Model results for annual system costs and LCOE in 2050 across the four scenarios

		Scenario 1		Scenario 2		Scenario 3		Scenario 4	
		Market	Best case	Market	Best case	Market	Best case	Market	Best case
System costs in 2050	Million € (2015)	12,485	10,767	14,510	12,015	14,147	12,135	12,274	10,688
RES-E	Million € (2015)	8560	7090	11,954	9838	6880	5215	8428	7071
Wind power	Million € (2015)	4101	3559	5270	4574	1178	1022	4685	4066
Solar PV	Million € (2015)	1310	947	2625	1899	4380	3168	871	630
Reservoir hydro	Million € (2015)	426	356	389	326	503	419	423	354
Biomass	Million € (2015)	1623	1423	2570	2236	81	67	1607	1406
CSP	Million € (2015)	1100	805	1100	805	739	539	842	615
Conventional	Million € (2015)	2953	2889	887	824	5744	5680	3001	2934
Hard coal	Million € (2015)	1635	1616	481	463	2265	2247	1822	1800
Natural gas	Million € (2015)	1001	965	361	326	2702	2666	912	876
Oil	Million € (2015)	317	308	44	35	776	767	267	258
Storage	Million € (2015)	936	758	1627	1318	1491	1214	810	655
Transmission grid	Million € (2015)	37	30	42	34	32	26	35	28
System cost reduction	%		– 14%		– 17%		– 14%		– 13%
LCOE in 2050	Ct./kWh	7.23	6.24	8.41	6.96	8.20	7.03	7.11	6.19
LCOE cost reduction	%		– 14%		– 17%		– 14%		– 13%
CO_2 emissions in 2050	Mt/a	13	13	0	0	28	28	13	13

Simulation results

Table 3 summarizes the key model simulation results for the four scenarios, each distinguished again between best-case and market financing cost assumptions derived from the downscaled electricity system model renpassG!S. We find that under market financing cost assumptions, annualized system costs (14,510 Mio. EUR), as well as average LCOE (8.41 EUR Ct./kWh) in 2050 are the highest in scenario 2, which is providing electricity for Morocco on a 100% RES-E basis. It needs to be noted that scenario 2 still has annualized cost for conventional technologies built earlier than 2050. Even if those were disregarded, the cost of scenario 2 would still be the highest. The scenario with the lowest overall system costs (12,274 Mio. EUR), as well as the lowest average LCOE (7.11 EUR Ct./kWh) in 2050, again for market financing costs, is scenario 4. Annual CO_2 emissions in 2050 are found to be highest (28 Mt CO_2/a) for the electricity system described by scenario 3, which is characterized by a high share of fossil fuel-based electricity production (Table 2). Scenario 2, on the other hand, which describes a 100% RES-E-based electricity system for Morocco, leads to a zero-carbon electricity sector in Morocco by 2050.

The sensitivity analysis regarding financing cost assumptions shows that, assuming best-case financing costs, average LCOE (Table 3) can be reduced substantially for all four scenarios. The reduction potential amounts to − 14% in scenario 1, − 17% in scenario 2, − 14% in scenario 3, and − 13% in scenario 4. The cost reduction potential is particularly high for the 100% RES-E based scenario (scenario 2). Since RES-E technologies are relatively capital intensive, a reduction in the cost of capital translates into even stronger cost reduction potentials when compared to relatively less capital-intensive electricity generation technologies, such as coal or gas.

Turning to overall system costs across the four different electricity scenarios for Morocco, our results indicate that de-risking RES-E investments can lead to cost competitiveness of a zero CO_2-emission electricity system (scenario 2) compared with the three mixed (RES-E and fossil fuel-based) scenarios at marked financing costs (Fig. 4). Comparing scenario 2 directly with scenario 3 shows that the relation of total system costs of the two alternative electricity scenarios can even be turned around. While total system costs are higher for scenario 2 (14,510 Mio. EUR) than for scenario 3 (14,147 Mio. EUR) given market financing costs, best case financing costs lead to lower total system costs in scenario 2 (12,015 Mio. EUR) than in scenario 3 (12,135 Mio. EUR). This result indicates that de-risking RES-E investments particularly pays off for 100% RES-E systems with a well-balanced portfolio of RES-E technologies (Table 2). In particular, the production capacities of wind and PV have to be carefully aligned in an electricity system in order to make most effective use of de-risking measures. The results show that the cost for additional transmission capacity between the defined regions is relatively low compared to the required investments into production capacity, as transmission capacity is already partly available in Morocco. Moreover, due to an assumed power line service life of 40 years [72], which constitutes a long

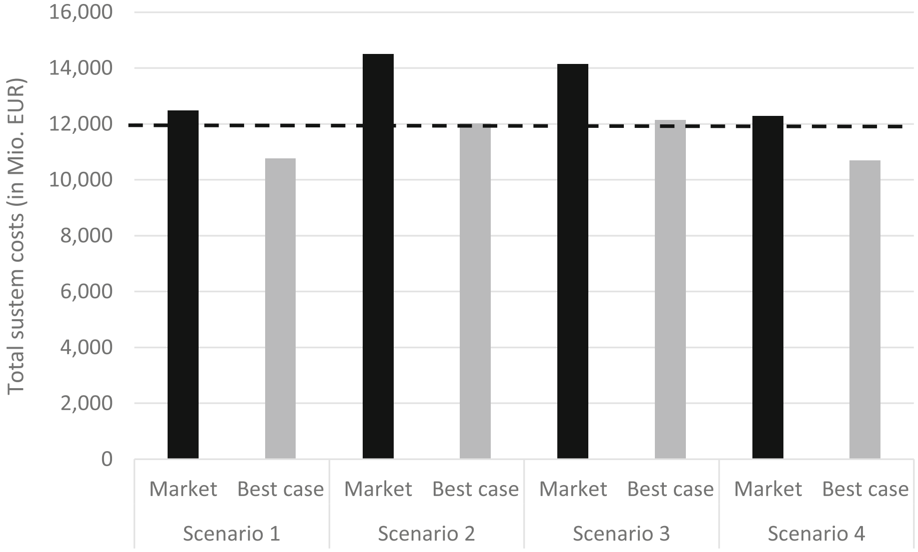


Fig. 4 Total system costs across the four scenarios (in Mio. EUR 2015). Dashed line resembles system costs for 100% RES-E (scenario 2) with best-case financing costs assumption

depreciation period, annualized transmission grid investment costs are comparably low and do not have a strong influence on resulting LCOE.

While the research activity mainly focused on the target year 2050, additional calculations of the evolution from today's power system to the potential future system settings in the target year were conducted. This allows us to assess intermediate targets and milestones, as well as a time-dependent comparison of the scenarios. In Fig. 5, two sets of key model results are depicted for the four electricity system scenarios. In the diagram on the left, the installed capacity in the decades from 2020 until 2050 is illustrated. The diagram on the right depicts the corresponding annualized investment costs broken down into RES-E capacity, non-RES-E capacity, storage capacity, and grid infrastructure. The diagrams highlight the range of the scenario results over time and allow the assessment of the correlation between the installed capacity and related investment costs. In 2020 and 2030, the results mainly differ between the scenarios due to differences in storage additions. From 2040 onwards, we observe a substantial increase in the capacity of RES-E technologies, which also translates into an increase in related investment costs.

While annualized investment costs in 2050, assuming best-case financing costs, are found to be highest for the 100% RES-E scenario (scenario 2 (Fig. 5b)), total system costs are even lower than those in scenario 3 (Fig. 4). This highlights that a 100% RES-based electricity system will require high levels of investment, but this is counterbalanced by comparably low operation costs. Even though no more fossil fuel-based electricity generation capacity is actively generating electricity in 2050 under scenario 2 (Fig. 5a), the long depreciation phase is reflected in still positive annualized investment costs for non-RES-E (Fig. 5b).

Figure 6 visualizes the benefits of improved financing cost conditions for the transition of Morocco's electricity system towards high shares of RES-E over time. Around the year 2030, when capital-intensive RES-E capacities, as well as associated investment costs start to rapidly increase, a reduction in financing costs kicks in to have substantial positive effects on annualized investment costs in each of the four scenarios. By 2050, annualized investment costs assuming best-case financing cost conditions are 20%, 20%, 23%, and 18% lower for scenarios 1 to 4, respectively.

Discussion

The existing literature mainly focuses on single technology assessments with regard to the effects of differences in investment risks and financing costs. Earlier results from research focusing on CSP investments in the MENA region showed that the implementation of a de-risking approach would lead to significant reductions of LCOE for electricity generated from CSP. However, even if financing costs can be substantially reduced (e.g., down to the level of financing costs in the European Union), this will on average only lead to a 39% reduction in LCOE across the region. This does increase the price competitiveness of CSP in comparison to fossil fuel-based electricity generation technologies, but still does not make it fully competitive as long as subsidies for fossil fuels in the region continue to exist [25]. While such studies shed light on context-specific details that may lead to variations in financing costs across different technologies and regions, here we follow a more comprehensive

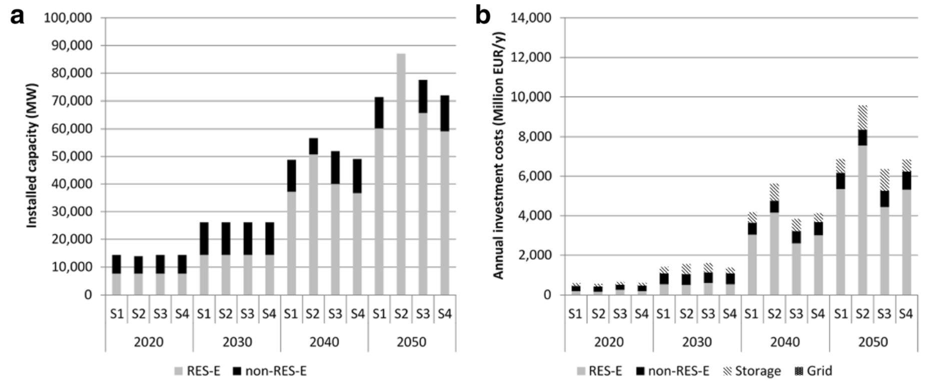


Fig. 5 Total installed capacity (**a**) and annualized investment costs (**b**) across the four electricity scenarios (S1 to S4) and assuming best-case financing costs (in MW and Mio. EUR 2015, respectively)

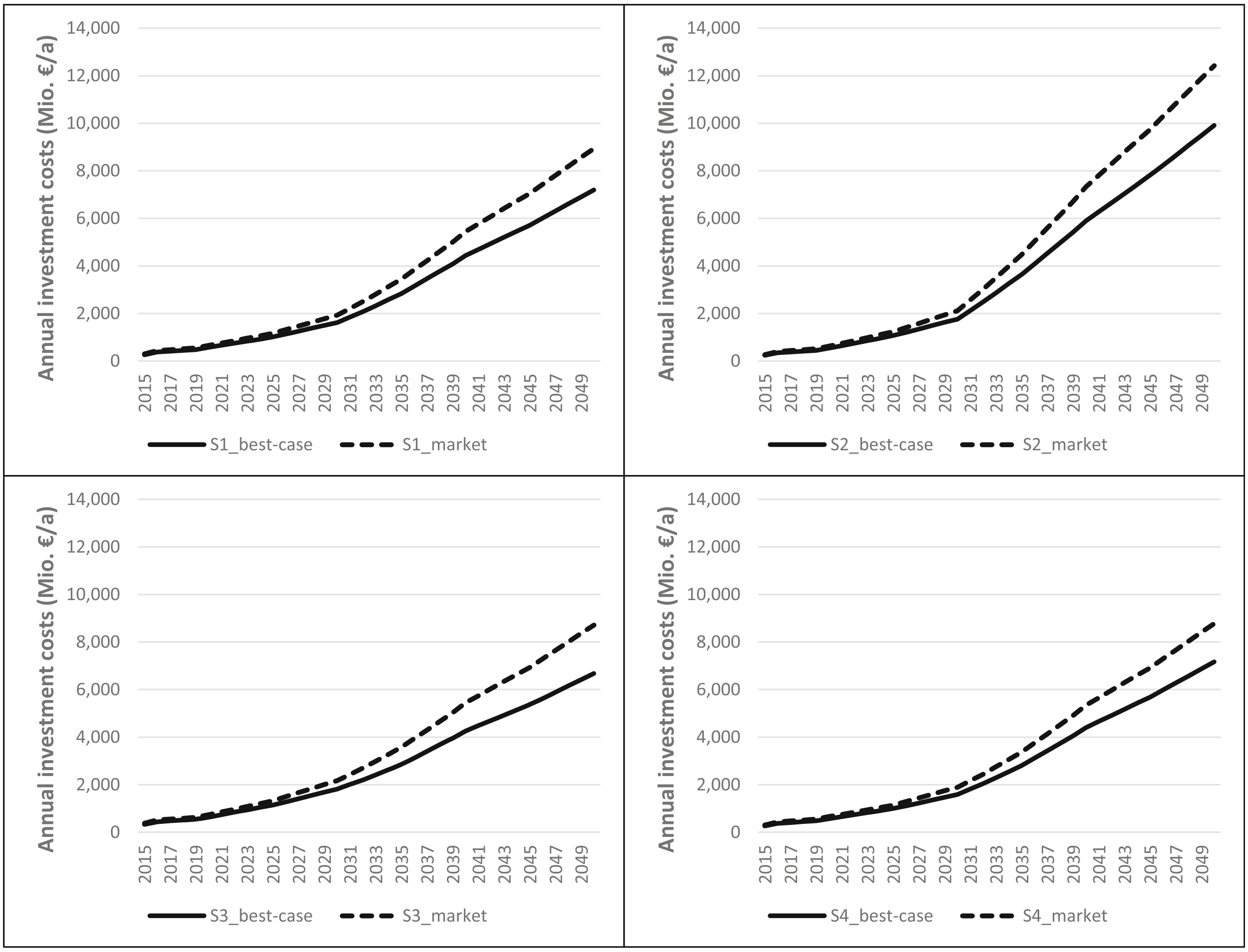


Fig. 6 Development of annualized investment costs from 2015 to 2050 across the four Moroccan electricity system scenarios (S1 to S4) distinguishing market and best-case financing costs

approach when assessing the role of financing costs for a fundamental transformation of the electricity system in Morocco. To effectively support planning in energy policy, an interlinked system of various generation technologies, each characterized by its own financing cost and risk profile, has to be assessed.

Our model-based assessment of different electricity scenarios, characterized by varying portfolios of electricity generation technologies, each with a specific risk and financing profile, suggests that even at the system level, de-risking may substantially reduce overall costs. The total system costs of a 100% RES-E-based scenario, co-developed with participants in stakeholder workshops in Morocco, may be reduced by up to 17% if best-case financing conditions (e.g., through the involvement of multilateral development banks) can be guaranteed, rather than market-based debt and equity interest rates. Moreover, our results indicate a potential cost competitiveness of a de-risked 100% RES-E electricity system with mixed-technology scenarios at marked financing costs. Such a comparison seems not only already legitimate today, but might even become more realistic in the future, given that financing costs for conventional fossil fuel-based electricity generation technologies will likely rise due to increasing default risks associated with such carbon-intensive investments. This is especially likely if the Paris Agreement's greenhouse gas (GHG) reduction plans are going to be implemented—as for example recently highlighted by the Task Force on Climate-related Financial Disclosures [73].

The modeling approach followed in this paper constitutes a simulation of scenarios pre-defined in participatory stakeholder processes. In particular, the operation of the technologies and their respective capacity as defined in the scenarios are modeled. While a full-cost investment optimization approach would result in a cost optimal solution [72, 74, 75], that is, an optimal mix of technologies and capacities, the simulation approach corresponds to an operational optimization that intentionally seeks to analyze the effects of pre-defined conditions (here, technologies and their capacities) on the overall power system [76]. Hence, our model results do not reflect least-cost electricity systems in terms of investment and operational costs, but an optimized operational behavior of the individual system elements. Nevertheless, the full system costs of technologically feasible pre-defined scenarios can be assessed with our modeling approach. The modeling results can act as inputs to further in-depth analyses of Morocco's future energy system. They might for instance be utilized with different simulation models in order to detect system bottlenecks and hot spots. The national power utility, as well as private power companies, can gain information about potentially required technologies and capacities, and eventually avoid stranded investments. Model outputs can thus be valuable inputs for holistic energy system planning, such as the development of long-term strategies and corresponding policies. A major benefit of this simulation-based and participatory modeling approach that we see in comparison to top-down optimization modeling techniques is that it opens the "black box" for potential end users of the model and its results. This increases transparency and leads to stakeholders taking co-ownership in the modeling exercise and its results, thus eventually increasing the political feasibility of the analyzed electricity scenarios.

A participatory approach in designing the energy transition in Morocco is limited by a centralization of decision-making power as well as technical decision-making philosophy when the majority of decisions are taken at the national level with the help of technical advisers and are then implemented at the national level through a top-down approach. The roots of this centralization of decision-making date back to a 1919 government decree, which gives formal ownership over collectively owned lands in Morocco, and therefore also for infrastructure deployed on these lands, to tribal confederations or ethnic collectivities. However, even though the tribal considerations were officially recognized as owners of the land, the decision-making authority was centralized at the Office of Indigenous Affairs, which became by today the "Direction of Rural Affairs of the Ministry of Interior". Similar centralization patterns are also reflected in the centralized legal architecture regarding deployment of RES and the limited participation possibilities in the decision-making regarding the needs of the project and the location. Only after technical decisions are made, the Moroccan state starts to engage with the local population, for example by explaining the need of the project. While decisions about the project are taken by officials at the national level, all tasks regarding negotiations with inhabitants of affected communities are transferred to the local ministry officials and elected representatives.

The participatory approach in the development of the scenarios allowed the analysis and comparison of technical options in the context of the views and estimates of workshop participants. The scenarios developed are therefore not to be read as the most probable, but rather as a map of potential future system settings. Moreover, the modeling results show potential settings of Morocco's future power system that need to be further analyzed, in particular, to the sensitivity of input parameters. The load level, for instance, strongly affects all modeling results and their impact, and thus should be analyzed in further detail. Even though the modeling results cannot directly be transferred to another country case due to differences in the power demand structure, the RES-E potential, and other parameters, they qualitatively highlight the key options, as well as obstacles a power system with comparable conditions might be facing. This should also be the subject of further research.

Conclusions and policy implications

The consideration of financing costs is crucial in developing socioeconomically feasible electricity scenarios with a high share of RES-E for Morocco and beyond. This is the first study to do that based on an inclusive and comprehensive stakeholder co-design process employing participatory techno-economic electricity sector modeling and focusing on portfolios of different technologies, rather than on individual technologies. Our results highlight that financing costs are a major driver of RES-E generation costs, hence the de-risking of investments will be crucial. Moreover, the insights gained at the workshops indicate that the choices of participants regarding different electricity generation technologies are strongly dominated by an economic rationale. Decision-making experiments during the workshops employing the renpassG!S model, as well as discussions on the parameters of the model, highlighted the importance of economic criteria such as electricity system costs or LCOE to the workshop participants. The perceptions of these stakeholders imply that measures are needed to tackle financial barriers that influence the financial feasibility of RES-E projects. This will require a comprehensive strategy focusing on different levels and aspects at the technology level, the financing source level, and the political level.

We highlight the following four policy recommendations:

1. Moroccan energy policymaking should focus on tackling financial barriers to RES-E investments by designing targeted de-risking policies, while keeping in mind the complex technological and economic interaction between different electricity generation technologies embedded in the overall power system. At the stakeholder workshops, concrete ideas for public de-risking policies were identified, such as an assurance of guarantees for power purchase agreements (PPAs) signed by private consumers, or sharing local commercial bank risks in financing RES-E investments. It could also be very opportune if the government of Morocco operates the public investment fund "Société pour l'Investissement en Energie (SIE)" to purchase shares in RES-E projects, thereby contributing to both the de-risking of RES-E investments and the mobilization of the required up-front capital for these investments.
2. One concrete option to foster RES-E investments in Morocco and the MENA region in general, is to further strengthen the involvement of MDBs and other international financial institutions. It is crucial to involve MDBs in the financing of RES-E for several reasons. First, the volumes of RES-E investments needed to achieve the decarbonization of Morocco's electricity system are significant. To foster private RES-E investments next to public ones, investors require support in terms of financing and risk sharing. The involvement of MDBs can contribute to the reduction of investment risks associated with financing, uncertainty about returns, and potential financial losses. Additionally, the involvement of MDBs can further contribute to the reduction of subjective risks connected to perceived barriers for project realization associated with investments into RES-E, and contribute to the so-called de-risking approach. While the importance of MDB involvement was generally echoed by the workshop participants, some actors argued that MDBs are already heavily involved in financing RES-E in Morocco. Based on the fact that RES-E technologies are becoming more and more cost competitive with conventional fossil fuel-based technologies, they suggested that it might become opportune for MDBs to start collaborating more with local and/or international commercial banks and investments funds in the near future.
3. In addition to the involvement of MDBs, we suggest considering further de-risking incentive policies, such as preferential loans, tax credits, feed-in-tariffs, and reduced land cost for power stations. Moreover, novel policy instruments such as hybrid bonds [77] that allow for the pooling of risks across a portfolio of divers RES projects will have to be considered to attain the levels of RES-E investments required for realizing the energy transition in Morocco and elsewhere.
4. Importantly, participatory scenario-based electricity systems modeling increases the socio-political feasibility of certain low-carbon development scenarios by allowing as many as possible different stakeholder voices to be heard and recognized in the process of finding a mutually agreeable consensus.

Endnotes

[1] RenpassG!S is based on the Open Energy Modeling Framework (OEMoF) [89–91]. Both the OEMoF framework and the renpassG!S model were primarily developed by Europa-Universität Flensburg.

[2] In the spreadsheet model, the order of utilization of dispatchable units was pre-defined based on the respective fuel's marginal cost.

[3] The RES-E projects and related financing costs assessed here cover public sector or PPP projects. Purely private sector projects might have quite different risk profiles and hence face different financing costs. However, due to the lack of publically available information on financing costs of private investment projects, we had to restrict our assessment accordingly.

Appendix

Table 4 Best case financing cost assumptions for specific RES-E technology investments in Morocco. Source: Own calculation based on [78–88], as well as personal discussions with developers (Masen, ACWA Power), International Technical advisory providers (Intec Gopa and Suntrace), and Moroccan Investment Banks (Upline Investment)

Technology	Share of debt financing (%)	Share of equity financing (%)	Debt interest rate (%)	Equity rate of return (%)
CSP	86.00	14.00	3.1	14
Wind	80.00	20.00	4.0	14
Geothermal	80.00	20.00	4.0	20
PV	86.00	14.00	3.1	14
Biogas	80.00	20.00	4.5	15
Reservoir hydro	82.00	18.00	5.0	15
Pumped-hydro storage	80.00	20.00	4.0	20
Hard coal	79.30	20.70	4.0	15
Natural gas	75.08	24.92	4.0	12
Oil	79.30	20.70	4.5	15

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Availability of data and materials
The datasets used and/or analyzed during the current study are available from the corresponding author on reasonable request. The renpass application, which was the starting point for the downscaled model developed in the current study, is available in the GitHub repository https://github.com/znes/renpass.

Authors' contributions
The study was designed by TS, with major contributions by SB, NK, and EMJ. NK, SB, with support by EMJ, carried out the participatory stakeholder workshop in Morocco and harvested the resulting insights. SB and MB developed and ran the model. TS and SB led the interpretation of the results. TS took the lead in authoring the paper; SB, NK, and EMJ assisted the writing of the manuscript. All authors read and approved the final manuscript. TS edited the manuscript.

Ethics approval and consent to participate
Not applicable.

Consent for publication
Not applicable.

Competing interests
The authors declare that they have no competing interests.

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