IAEA TECDOC SERIES

IAEA-TECDOC-1885

IAEA-TECDOC-1885

Nuclear–Renewable Hybrid Energy Systems for Decarbonized Energy Production and Cogeneration

Proceedings of a Technical Meeting

IAEA
International Atomic Energy Agency

NUCLEAR–RENEWABLE HYBRID ENERGY SYSTEMS FOR DECARBONIZED ENERGY PRODUCTION AND COGENERATION

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PROCEEDINGS OF A TECHNICAL MEETING
HELD IN VIENNA, 22–25 OCTOBER 2018

INTERNATIONAL ATOMIC ENERGY AGENCY
VIENNA, 2019

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Printed by the IAEA in Austria
October 2019

IAEA Library Cataloguing in Publication Data

Names: International Atomic Energy Agency.
Title: Nuclear–renewable hybrid energy systems for decarbonized energy production and cogeneration / International Atomic Energy Agency.
Description: Vienna : International Atomic Energy Agency, 2019. | Series: IAEA TECDOC series, ISSN 1011–4289 ; no. 1885 | Includes bibliographical references.
Identifiers: IAEAL 19-01270 | ISBN 978–92–0–161419–3 (paperback : alk. paper) | ISBN 978–92–0–161519–0 (pdf)
Subjects: LCSH: Hybrid power systems. | Nuclear energy. | Renewable energy sources. | Cogeneration of electric power and heat. | Carbon dioxide mitigation.

FOREWORD

With 185 parties having ratified the Paris Agreement under the United Nations Framework Convention on Climate Change, interest has increased in finding viable, financially sound and integrated solutions for providing low carbon, affordable and resilient energy production for the generation of electricity, chemicals, heat and fuels. Two principal options for low carbon energy are renewables and nuclear energy. While much research has focused on these options separately, the possible synergies between them have yet to be fully explored.

In June 2016, an international workshop was organized by the Idaho National Laboratory and the National Renewable Energy Laboratory (NREL) and held at the NREL Research Support Facility, in Golden, Colorado, United States of America. The international workshop explored synergies between nuclear and renewable energy sources in electricity, transportation and industrial sectors, recognizing that deep decarbonization will require efforts that go far beyond the electricity sector alone. The workshop brought together experts across the international community from many disciplines who are engaged in designing, demonstrating and implementing nuclear–renewable hybrid energy systems. The goal was to initiate discussions on a potential framework for increased international cooperation and to explore ways to accelerate significant reductions in the emission of greenhouse gases.

In response to the workshop and increased interests in Member States, the IAEA organized the Technical Meeting on Nuclear–Renewable Hybrid Energy Systems for Decarbonized Energy Production and Cogeneration, in Vienna, 22–25 October 2018, to review and discuss concepts and innovative solutions. The meeting included presentations on the latest innovative concepts addressing the challenges of using a combination of nuclear and renewable energy sources. A total of 24 participants from 17 Member States and two international organizations attended the meeting. This publication is the proceedings of the technical meeting and presents summaries of the technical and discussion sessions, conclusions and recommendations made at the meeting and the papers submitted.

The IAEA gratefully acknowledges the contributions of the participants and their presentations and submitted papers. The IAEA officers responsible for this publication were T. Jevremovic of the Division of Nuclear Power and A. van Heek of the Division of Planning, Information and Knowledge Management.

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1. INTRODUCTION

1.1. BACKGROUND

There is an increased interest in exploring the synergies of nuclear and renewable energy sources. Because of the variability in both the generation of renewable energy sources such as wind and solar and the electricity demand (hourly, seasonal), there is a need to support variable renewables with long term energy storage or alternative, flexible power sources. Nuclear power presents a low carbon option for supporting the increased penetration of variable renewables on the electricity grid, though nuclear plants have historically not often operated in load following modes for regulatory and/or economic reasons. In addition to interaction on electrical grids, synergies can be found through more direct coupling of energy systems, as nuclear–renewable hybrid energy systems — consisting of both nuclear and renewable energy sources for electricity or cogeneration purposes.

As climate mitigation policies call for more restrictions on the application of fossil fuels, opportunities emerge for low carbon generating technologies. Therefore, in many countries an increase of variable renewable capacity can be observed, increasing also the need for backup power during periods of low wind and cloudy weather. This creates an opportunity for nuclear power as a dispatchable low carbon generating technology. However, from an economic point of view, a nuclear power plant should be running as many hours as possible, as it is a capital intensive asset. During the period with unfavourable weather conditions for variable renewables, in deregulated energy markets kilowatt hour prices may be driven upwards, which could be compensating for a lower percentage of operating hours of the nuclear power plant. When already upfront designing for complementary operation of the two technologies in a hybrid system, an even better efficiency could be reached, both in the energy and the economic sense. In addition, in a tightly coupled hybrid system, the electricity generated by the variable renewable systems and the nuclear plants could be used to produce hydrogen or another artificial fuel. In addition, if economically more attractive, the heat from the nuclear reactor could be used directly for the same products.

In June 2016, an international workshop was organized by the Idaho National Laboratory (INL) and the National Renewable Energy Laboratory (NREL) and held at NREL's Research Support Facility in Golden, Colorado, United States of America [1]. The international workshop focused on exploring synergies between nuclear and renewable energy sources crossing the electricity, transportation and industrial sectors, recognizing that deep decarbonization will require efforts that go far beyond the electricity sector alone.

In response to that workshop, the International Atomic Energy Agency (IAEA) organized the Technical Meeting on *Nuclear–Renewable Hybrid Energy Systems for Decarbonized Energy Production and Cogeneration* in Vienna, 22–25 October 2018, to review and discuss concepts and innovative solutions pertaining to nuclear–renewable hybrid energy systems for decarbonized energy production and cogeneration.

1.2. OBJECTIVE

The main purpose of the meeting was to provide Member States and stakeholders with an update on the status of and new concepts in nuclear–renewable hybrid energy systems for decarbonized energy production and cogeneration. The meeting provided a forum to exchange knowledge on these technology designs and related innovations, and to gather information and develop relationships that lead to collaborations to address these issues.

Contributions in the form of full papers, presentations and session discussions resulted in a number of recommendations and conclusions, which led to the initiation of developing IAEA Nuclear Energy Series publication during 2019–2020. A total of 24 participants from 17 Member States and two International Organizations attended the meeting. It included three technical sessions:

(1) National Approaches;
(2) Integration of Renewables with Nuclear Installations;
(3) Role of SMRs in Integrated Energy Systems and Cogeneration.

1.3. SCOPE

This TECDOC presents Proceedings of the Technical Meeting on *Nuclear–Renewable Hybrid Energy Systems for Decarbonized Energy Production and Cogeneration*, which was held in October 2018. It includes summary of technical sessions and includes the full papers which were submitted to and presented at the meeting.

1.4. STRUCTURE

Section 2 of this publication summarizes technical sessions and discussions from the Technical Meeting. Section 3 of this publication provides the conclusions and recommendations from the Technical Meeting. Included also are Member States' full papers submitted to and presented at the Technical Meeting, organized by technical session.

2. SUMMARY OF MEETING SESSIONS

2.1. TECHNICAL SESSION I: NATIONAL APPROACHES

This technical session consisted of eight presentations and was followed by a discussion session. In this session, Member States presented national approaches to deployment of nuclear and renewable energy sources; additionally, the R&D efforts for the development of hybrid energy systems and nuclear fleet management strategies were outlined and discussed.

The first presentation, entitled *National Energy Mix: Renewables and Nuclear Power in Bulgaria* (N. Ivanova, Kozloduy Nuclear Power Plant), discussed the increased use of renewable energy sources in Bulgaria. In March 2007, European Union energy policy proposed a shift to low carbon, increased security and competitive energy sources. In 2015, nuclear energy was acknowledged as an important part of meeting the component decarbonization goals. The national energy policy in Bulgaria focuses on limiting the country's dependence on imported energy resources, mitigating the effects of climate change, developing a competitive energy market and increasing energy efficiency. Bulgaria has a diverse energy mix, however has a significantly lowered electricity production due to changing availability. As a result, the electricity market is heavily reliant on imported fuel. Bulgaria is currently on track to meet energy goals and has a high solar availability; however, it is difficult to regulate in many parts of the country. The presentation described how special attention needs to be paid to maintaining a demand load despite increased use of variable renewables and subsequent loss of regulating capacity. Possible ways to address this is through storage hydropower plants, small modular reactors (SMRs) capable of flexible operation or balanced renewables. Pumped storage hydropower plants are not a reliable option for Bulgaria given the low water resources in the country. Thermal power plant cogeneration is being explored as an option for district heating; no additional cogeneration plans are in place as of 2019.

The second presentation, entitled *Hybrid Nuclear-Renewable Energy Systems for Sustainability and Climate Change Mitigation in Turkey* (H. Caliskan, Usak University), described the national energy mix and energy goals. In Turkey, there is a large potential for renewable energies with wind, biomass, hydropower, geothermal and solar. The first nuclear power plant is expected to meet Turkey's increased energy demand. Turkey is the 6th largest electricity market in Europe, 5th largest consumer, and 4th largest gas consumer. In 2017, the energy profile consisted of 32% hydroelectric, 31% natural gas, 11% domestic coal, 10% import coal, and 13% renewables. Goals for 2019 include to reduce natural gas below 30%, to increase gas storage by 10% of consumption, increase electricity generation from local coal, hydroelectric and renewable sources. The goal by 2023 is to raise total capacity to 120 GW, increase renewable to 30%, maximize hydroelectric, increase wind, geothermal usage, extend transmission lines, introduce smart grids, raise natural gas storage, commission nuclear power plants and to increase coal capacity with a new coal plant technology that is more environmentally friendly. In the west of Turkey, wind energy is considered the best renewable option, while southern areas have large capacity for solar. Three nuclear power plants are planned, to begin operation one each in 2023, 2025, 2031. The presenter from Turkey also explained how solar and nuclear could be coupled to heat steam to the turbine in a superheater and in the reheater. The solar technology used for this application could either be a solar tower receiver or solar parabolic collectors. Wind turbines (or solar voltaic panels) could also be used together with nuclear to supply a thermal storage system.

The third presentation, entitled *Synergies Between Nuclear and Renewables, the French Perspective* (M. Berthelemy, CEA Saclay), explained how, because of its large nuclear capacity, France has already achieved a high level of decarbonization. The country, however, continues to support expansion of renewables, build low carbon mixes, extend load-following and other technical capabilities and extend R&D and demonstration. Nuclear power plants in France can typically perform two load following operations per day at 5% power/minute. Plants in France can go down to as low as 20% power, while some plants have to shut down in summer due to lowered demand. The French Energy Transition law (2015) seeks to reduce greenhouse gas emissions 40% by 2030, reduce energy consumption 20% in 2030 and 50% in 2050, and reduce use of fossil fuels 30% by 2030. For nuclear, the goal is to reduce to 50% generation in 2035, and keeping installed capacity capped at the current level of 63.2 GW_e. Two renewable nuclear energy mix scenarios were used as references to push for the increased use of renewables and reduction of carbon dioxide production. In these, nuclear capacity is to be reduced to 50% and 55% capacity. The load following capability and seasonal flexibility of nuclear both play a significant role in supporting the integration of renewables. As French plants reach retirement, new plants may need to be installed to maintain capacity goals. Renewables are planned to exceed 50% before 2050. In the long term, nuclear power can provide a role in hydrogen production to support energy storage by diverting excess generation. Research activities in this area consist of enhancing load following capability and implementation (preventative maintenance, water chemistry monitoring, digital tools for control room operators), future NPP designs to integrate flexibility needs from the design stage, load-following linked to Generation IV technologies (SFR, SMR) and non-nuclear operation to support decarbonization of non-electrified sectors (cogeneration). A French initiative to develop a 170 MW_e SMR is gaining pace, with single or multi reactor solutions and flexible operation whereas France currently utilizes a fleet programme to initiate load following operations.

The fourth presentation, entitled *U.S. Research & Development Status for Integrated Nuclear-Renewable Energy Systems* (S.M. Bragg-Sitton, Idaho National Laboratory), discussed investigations in the United States of America on new reactor technologies and repurposing or retrofitting of existing large water cooled reactors to support non-electric applications. A number of applications for new reactors could include remote villages (heating and electricity) or supplying heat/electricity to industrial complexes. There are several challenges facing nuclear in the United States, some of the most notable drivers for investigations for repurposing and retrofitting large reactors are that:

- Electricity can fall to even negative pricing during the day;
- Natural gas has put economic pressure on nuclear power plants, causing premature plant closures.

Developing flexibility will allow large water cooled reactors to circumvent premature closure. Two key areas for integrated energy systems include technical feasibility and economic feasibility requiring efficient capital utilization. One of the primary applications being explored is hydrogen generation. Three case studies were presented, focused on: nuclear–renewable–water integration in Arizona, nuclear–industrial process variable hybrid in the Midwest and a nuclear–chemical plant integration with several tools being used to analyse the optimum configurations. An experimental demonstration (Dynamic Energy Transport and Integration Laboratory) is under construction at INL which will emulate a reactor and hydrogen production facility. Economics are central; however, it needs to be understood that other economic factors must be considered such as baseload versus variable abilities and potential for carbon taxes. Non-economic values may be appropriate for implementation in these studies. There is a requirement for coordination between different sectors for multiple application reactors; this is something that is recognized but not entirely solved as it needs to be a profitable venture for both parties in order to move forward.

The fifth presentation, entitled *Synergy of Nuclear and Renewable – AQABA City Pathway to Net-Zero Emissions* (K. Araj, Jordan Atomic Energy Commission), described Jordan's high dependency on fossil fuels from neighbouring countries and its resulting highly volatile energy security. Natural gas, renewable technologies, oil shale and nuclear energy are being employed to solve energy needs. Jordan terminated its large reactor plans and is now pursuing SMRs while also noting that increasing the share of local resources is paramount. The Jordan Energy Strategy 2025 aims for 25% nuclear and renewable net generation (15% nuclear, 10% renewable). Nuclear generation coupled with a photovoltaic system can provide a high availability baseload with a generation system geared for peak load. Aqaba is the only coastal city in Jordan and a high temperature gas cooled reactor coupled with a photovoltaic system can provide electricity and cogeneration resources. However, due to seismicity, sites are chosen at significant distances from Aqaba. Photovoltaic sources may be used to pump water to cool a nuclear power plant and provide water for desalination. Nuclear could replace fossil load following and desalination applications and a nearby industrial zone can utilize steam or hydrogen produced.

The sixth presentation, entitled *Challenges and Potential Benefits of Cogeneration in Romania –The Impact on Energy Cost and Decarbonization* (I. Prodea, RATEN Institute for Nuclear Research Pitesti), explained that Romania's energy sector has faced challenges in the last two decades including: the need to replace fossil fuelled power plants, the need to build new stable and reliable electricity generation systems and the intermittency of renewable energy sources. Key objectives are to reduce energy poverty and consumer vulnerability, assure secure clean energy supply and modernize the governance of the energy system. One factor in this is the development of high efficiency cogeneration and modernization of centralized heating distribution systems. Analyses were performed for no cogeneration, cogeneration without additional costs and cogeneration with 20% larger investment costs. Each case had four scenarios for greenhouse gas restrictions of various percentages. These analyses concluded that it is impossible to meet heating needs with 90% greenhouse gas reduction in Romania. Heat prices can become unsustainable if greenhouse gas restrictions are too significant. The main challenges regarding cogeneration include the ongoing process of decommissioning existing cogeneration units, heat cost is increasing to that prior to cogeneration introduction and lack of services offered to consumers who are tempting to migrate to individual heating solutions.

The seventh presentation, entitled *Renewable Energies in Algeria* (B. Belarbi, Sharikat Kahraba wa Takat Moutadjadida (SKTM), Sonelgaz), discussed Algeria's developing renewable and diversifying energy sources. The majority of Algeria's renewable energy plans are photovoltaic, with wind as a secondary component. Different solar technologies are currently being tested. Existing solar infrastructure has greatly reduced the carbon dioxide emissions from the country. Nuclear energy meets Algeria's needs due to its cost competitiveness and the continued production without greenhouse gas emission and can support the expansion of electricity needs. Algeria is planning to develop their first nuclear plant following 2030; seven sites have been selected as candidates which will be studied, and technologies are being watched. Currently, no supplier or technology has been chosen. The renewable energy program will meet needs up to 2030 and the grid is being developed for renewable energies. Nuclear and renewable synergy must be considered in these future developments.

The eighth presentation, entitled *Impact of Introduction of Renewables on Power Economics and Grid Operations in Pakistan* (N. Jamal, Pakistan Atomic Energy Commission), explained how Pakistan historically has had 30% to 38% energy imports. One reason for this is that domestic supplies of coal are expensive due to geological factors. The viability of renewable energy sources varies: there is significant room for expansion of hydropower, there is only one particularly exploitable wind resource site and there is a large potential for solar. A simulation was performed which assessed renewable energy generation. With storage available, the need for baseload is decreased. For low renewable penetration, generation with storage was more expensive; for larger renewable implementation, generation with storage was cheaper than without.

Following this technical session, meeting participants discussed expected R&D and areas for international collaboration. This discussion identified motivations for pursuing deployment of hybrid energy systems as well as gaps which inhibit their implementation as shown in Table 1.

TABLE 1. MOTIVATION AND GAPS FOR PURSUING DEPLOYMENT OF NUCLEAR–RENEWABLE HYBRID ENERGY SYSTEMS

MOTIVATIONS	GAPS
— Economics; — Carbon mitigation; — Power system management; — Energy security.	— Energy planning and balance; — Policy structures are diverse and not shared; — Safety assessment; — Cost, especially for developing countries, is a potentially diversionary motivator; — Developing countries are unable to access or utilize tools and knowledge available from developed countries; — Understanding of transferability of tools; — International discussion on electricity system modelling tools, understanding of key areas for modelling (e.g. weather pattern effects on renewables).

2.2. TECHNICAL SESSION II: INTEGRATION OF RENEWABLES WITH NUCLEAR INSTALLATIONS

This technical session consisted of nine presentations, including one from OECD/NEA and one from the IAEA, and was focused on the integration of renewables with nuclear installations.

The first presentation, entitled *Opportunities and Challenges for Nuclear-Renewable Hybrid Energy Systems* (M. Ruth, National Renewable Energy Laboratory), discussed the conclusions of various case studies on the profitability of hybrid energy systems. This requires analysis of profitability, profitability compared to natural gas alternatives and competitiveness in grid resource adequacy markets. Four different reports were created: (a) liquid transportation fuel by thermal interconnection, (b) reverse osmosis desalination by electrical interconnection with no purchase of grid electricity, (c) thermal energy in an industrial park by thermal interconnection with possible purchase of grid electricity and (d) hydrogen production by electrical interconnection or thermal interconnection for high temperature electrolysis with possible purchase of grid electricity. For each case study, optimal configurations and internal dispatch were analysed under various product prices. Case studies resulted in the following conclusions:

- Conclusion #1: the optimal configurations are primarily dependent on whether subsystems would be profitable independently; however, grid connection costs are considered negligible and there is no value for inertia or resilience in this study.
- Conclusion #2: industrial processes maximize profitability by operating the maximum number of hours in a year. Systems with lower hourly income required from industrial process may optimally reduce the industrial product to receive a capacity payment.
- Conclusion #3: lower capital cost industrial processes are more likely to utilize flexibility to switch between electricity and industrial product more often than high capital cost configurations; this flexibility increases the number of profitable situations.
- Conclusion #4: nuclear reactors may be competitive selling thermal energy; providing a thermal energy market exists and they can access that market.
- Conclusion #5: higher capacity payments lead to more optimal configurations that provide grid support; but a sufficient industrial product price is still critical.

The second presentation, entitled *Nuclear and Renewables in Low-Carbon Electricity Systems: A Synthesis of OECD/NEA Studies* (M. Cometto, OECD/NEA), discussed the increased use of variable renewable generation in OECD member countries. A complete reconfiguration for electricity generation must be achieved by 2050 and nuclear is a significant contributor to the proposed energy generation mix. Renewables increase the volatility of electricity markets and have greatly affected the needs for transmission and distribution infrastructure which have in turn had a large impact on baseload technologies such as nuclear power. The NEA System Cost II study performed six scenarios and two sensitivity scenarios with different shares of variable renewables. The electricity demands become increasingly difficult to meet for large amounts of variable renewable energy sources. Larger increases to installed capacity must be made to meet regular steps of decarbonization increase. The total cost of generation increases with the share of variable renewable in the system. Low carbon generation is inevitably more capital intensive than the current energy mix. Decarbonizing to the Paris Agreement requires efforts from both government and industry: carbon tax implementation may be necessary to meet goals and emissions trading is an attractive alternative but with uncertain prices. Competitive short term markets are proven to be effective for cost efficient dispatch; however, provide an inadequate framework for generation. Adequate provision of capacity, flexibility and infrastructure for transmission and distribution must be supplied. Frameworks for long term investment in low carbon technologies, such as feed in premiums or direct capital support, are necessary. Internalising system costs should be maximized through profile costs, balancing obligations or connection costs. Carbon pricing remains the first and best policy option.

The third presentation, entitled *Resilient Interconnected Micro Energy Grids for Energy and Transportation Infrastructures* (H. Gaber, University of Ontario Institute of Technology), discussed micro energy grids with energy storage systems which were used to build a business model. For this, a superstructure is built out of generation methods, energy policies and supply to energy users (supply chain and production chain). A ‘micro energy grid’ is established from a library of models in the supply and production chains. Building generic blocks are created according to input/output. Transportation, water, thermal, electric and gas networks are interconnected in micro energy grids. Optimization rates performance on sociocultural, economic, environmental, reliability/safety/security and technical factors. The specific consideration of flywheel energy storage systems was discussed in depth. For a variety of events, a microgrid with flywheel energy storage coupled with a SMR was considered.

The fourth presentation, entitled *An HTGR and Renewable Energy Hybrid System for Grid Stability – Assessment of Performance, Economics and CO_2 Reduction* (X. Yan, Japan Atomic Energy Commission), explained that Japan is committed to greenhouse gas emission reduction

26% by 2030 and 80% by 2050. Power generation, transportation and steelmaking are large contributors to current emissions. A high temperature gas reactor can be applied to assist in decarbonization of each of these. Nuclear can replace fossil thermal power and reduce cost by reducing the use of pumped storage. Adjustment costs (efficiency drops, start and stop of thermal, hydro storage, securing generation facilities for renewable energy) are in hundreds of billions of yen per year for promotion of solar and wind power. A cogeneration plant can be coupled with a high temperature test reactor as a demonstration plant for a cogenerating plant design, GTHTR300. The reactor can respond to 75% variable power generation on the order of hours or days by controlling power through gas pressure and bypasses. In response to short term demands, on the order of seconds or minutes, thermal inertia of the core can absorb 20% power fluctuations and coolant pressure and turbine speed can be adjusted with no thermal power being changed. Power generation cost is relatively unaffected between base load and load follow; however, hydrogen production cost increases from load following. A case study of hybrid power cogeneration for Japan was presented. In this study, high temperature gas cooled reactors (HTGRs) replace coal fired plants and are used for 40% of hydrogen production from 112 four module plants. In industry, 20% of heat is supplied by HTGR. The systems could make a large contribution to decarbonization in Japan and could be deployable in the 2030s through accelerated development.

The fifth presentation, entitled *GIF Activities on Nuclear-Renewable Hybrid Energy Systems* (M. Berthelemy, CEA Saclay), discussed the Generation IV International Forum (GIF) technology goals, a legal framework in the Technology Roadmap released in 2002, which identified promising technologies, and the Framework Agreement in 2005. An update of the Technology Roadmap was published in January 2014, and an update of GIF R&D Outlook released this year. One area where GIF is considering is to extend the reach of R&D activities toward integration with renewables. Generation IV goals include sustainability, safety and reliability, economics, proliferation resistance and physical protection. GIF is looking to include flexibility capabilities in response to expected increases of intermittent renewables. For policy issues, flexible operation, hybridization and cogeneration and recognition of reliability are needed. From R&D, fuel optimization, material thermal cycling, waste heat rejection and control systems are needed. Key conclusions and recommendations are as follow:

— Beyond frequency regulation, the economics of flexible nuclear operation can be challenging under current market structures.
— In some countries, existing light water reactors can already operate in load following mode with increasing response. Penetration of renewables is likely to increase by Generation IV reactors reaching deployment. Given the ongoing developments it is difficult to determine the specific requirements for Generation IV reactors.
— Beyond load following, large scale energy storage and cogeneration applications could allow flexible operation of Generation IV reactors while ensuring overall high capacity utilization.
— Policy and market driven challenges could be more formidable compared to technical challenges of designing the reactors for flexible operation. Existing market designs do not always value reliability aspects of supply. This also applies to the sustainability attribute of Generation IV reactors with a closed fuel cycle.

Discussion following first portion of this technical session focused on impacts of energy policy on the introduction of hybrid energy systems. This took form of identifying ‘helpful’ and ‘deterrent’ policies as in Table 2.

TABLE 2. HELPFUL AND DETERRENT POLICIES FOR NUCLEAR–RENEWABLE HYBRID ENERGY SYSTEMS

HELPFUL POLICIES	DETERRENT POLICIES
— Carbon reduction (goals, tax/credit); — Promotion of coexistence/cooperation of nuclear and renewables; — Development of planning tools for implementation; — Energy security and independence.	— Nuclear taxes; — Lack of established disposal mechanism.
NOTES	
— Energy storage prevents negative pricing and provides a possible solution to market losses. — Backups to nuclear as heat provider in cogeneration applications.	

In a sixth presentation, following this discussion, the IAEA (T. Jevremovic, A. van Heek) presented the activities of the Nuclear Power Technology Development and Planning and Economics Studies Section activities relevant to the technical meeting.

The seventh presentation, entitled *Gen Energija Enhancing Efficiency of NPP Krsko with Cogeneration and Optimization of Hydro Power Plant Operation in Combination with NPP Cooling Cells* (K. Debelak, GEN energija d.o.o.), explained that Slovenia's nuclear power plant is seeking to extend its operating lifetime by 20 years and has considered cogeneration as a potential area for enhancing the plant's economics. Following Fukushima, the plant is undergoing refurbishing. Areas considered for cogeneration include district heating, process steam, district cooling and agricultural needs; however, agricultural needs and district cooling were found to be economically infeasible due to the necessary distance of transport. District heating to Krsko and Brezice have been considered as have industrial steam supplied to two consumers at a 3 km distance. For district heating steam–water heat exchange is used and for industrial steam supply steam–steam heat exchange is used, and pricing is competitive. District heating is regulated in the area and cannot be used to make profit, however industrial steam supply is not. Slovenia's nuclear power plant faces restrictions due to the temperature of coolant water and availability of coolant water and is supported by hydroelectric power plants. By operating in coordination with the hydroelectric power plants and monitoring meteorology and electricity markets, potential savings of a few MW over a few days were recorded. The drivers for cogeneration are more for public acceptance and environmental impact, rather than primarily economic.

The eighth presentation, entitled *Analysis of Offering Continuous Level of Power to Electricity Market from Wind Plant and Back-up Plant – What Flexibility Should Have the NPP?* (Ž. Tomšić, University of Zagreb), discussed an analysis of decarbonization strategies for Croatia. The motivation for this analysis was the long term low carbon development strategy for 2050. Possible strategies include: increase efficiency of electricity production and consumption, renewable energy sources, Croatian Nuclear Energy Program, additional utilization of hydro potential and thermal power plants with carbon capture and storage (too expensive for practical application). The government plans to force small incremental increases in renewable shares. SMRs are considered as an option to support renewables and analyses are being performed to maximize the capacity factor of plants. Load following capabilities are desirable, but it is unclear to what extent load following operations can be performed. The priority is for the stability of the power system — in each moment, consumption and production of electricity generally should be the same. Due to forecasted increase in capacity of variable renewables, greater back up capacity and energy storage capacity are necessary. Flexibility may come from flexibility of generation units, electricity storage, interconnections and demand side management. Renewable variability limits their participation in the energy market. The analysis considered a combined cycle gas turbine (CCGT) plant wind generator hybrid system. CCGT plants can deal with frequent changes to load, offering generation flexibility which can be used to propose needs for nuclear hybrid systems. The analysis was done using the PLEXUS tool. Three cases were analysed: (a) a fixed amount of power equivalent to the maximum capacity of wind, (b) greater than the total installed wind capacity above minimum stable power output of the CCGT and (c) flexible production from the CCGT. The first and second cases provide a flat level of generation. In case (a), the CCGT had a large variation in the unserved power different from the flat value depending on the time resolution of adjustments. In case (b), unserved power was reduced with the CCGT following better due to the 'minimum stable capacity' which means the CCGT did not need to shut down. The fuel price could render the system economically infeasible during periods of high price. Limiting ramp up and start rate were limiting in these cases. In case (c), different CCGT configurations (modular gas turbines) were compared with different wind patterns. The addition of gas turbines allowed for significant reductions in the cost of production and unserved energy. After one additional turbine, returns on additional turbines were smaller. Similar to this study, there is a need to improve the economic competitiveness of SMRs through flexible operation.

The ninth presentation, entitled *Nuclear Power Plant as "Thermal Hub" with Renewable Energy* (R. Takahashi, Mitsubishi Hitachi Power Systems, Ltd.), discussed a conceptual 'thermal hub', developed by Mitsubishi Hitachi Power Systems, which utilizes concentrated solar power to provide additional heat to nuclear power plant systems and output nuclear power plant waste heat to ocean thermal energy conversion. A hybrid concentrated solar power system can support heating in a solar thermal reheater supplying steam to the low pressure turbine. Such a system could be applied to existing nuclear power plants. With solar heating, the turbine efficiency is improved through reduction in steam 'wetness'. The preliminary economic study shows that a small increase over the sum of individual generation systems occurs in the hybrid system. This corresponds to a significant decrease in levelized cost. In the other case, ocean thermal energy conversion can be performed in a hybrid nuclear system. Water heated by the nuclear power plant can be output to ocean thermal energy conversion, expanding the potential locations for use of such systems. This system would consist of a large evaporator placed at the plant discharge location.

The second discussion of this technical session discussed coordination with large scale power systems, transmission and planning. For each of the following, there are technical, market, and regulator or policy challenges:

— Coordination for new nuclear and new hybrid energy systems. New builds can plan for hybrid systems rather than retrofit or reassess the integration of hybrid systems. This plays into several areas of plant design and planning: safety, site selection, design characteristics, technical capabilities, etc. The IAEA could develop and promote standardized tools to provide accurate costing and planning. In terms of IAEA, there is a need to consider how to work together to balance accuracy, simplicity, etc. through essential features to provide easy to use tools. There is a difficulty in connecting anything to the primary from a regulatory standpoint due to potential safety concerns, corresponding to a loss in performance. Impact of cogeneration on accident scenarios such as loss of load or loss of heat sink should be analysed. Would nuclear be the leader in hybrid systems or will it be a joint venture between renewable and nuclear?

— Coordination for existing nuclear. Different capabilities for plant control and changes. Existing plants often have to incorporate retrofits post-Fukushima and additional retrofitting may be deterrent. There is a need for education. During retrofitting it is also possible to perform economic retrofitting in parallel with safety retrofitting. In the US retrofitting is almost complete, Europe is very far along, Japan is dealing more significantly with major and costly upgrades as a limiting factor for time and the incorporation of hybrid systems at this time is difficult or impossible. At some level of regulation, non-nuclear load following options may be necessary. What characteristics must be considered for the difference between on-site and off-site hybridization?
— Coordination with other systems (e.g. heat integration, hydrogen coordination).

2.3. TECHNICAL SESSION III: ROLE OF SMRs IN INTEGRATED ENERGY SYSTEMS AND COGENERATION

This technical session consisted of eight presentations, including one from the European Commission and three from the IAEA on the role of SMRs in integrated energy systems and cogeneration.

The first presentation, by the IAEA (I. Khamis), discussed IAEA activities on cogeneration of heat and power. Desalination, hydrogen production, and heat for industry are important applications of nuclear reactors in non-electric applications. The IAEA develops models for economic analysis, assessment of safety environmental and technical considerations, tool development, and support for near term deployment of nuclear power plants.

The second presentation, entitled *Flameless Calcination of Minerals using Concentrated Solar Power (CSP) and High Temperature Gas-Cooled Reactors (HTGRs) – Opportunities for Nuclear-Renewable Hybrid Energy Systems* (N. Haneklaus, RWTH Aachen University), discussed the potential application of nuclear reactors in mineral processing. Ore grades has dropped significantly over time due to large scale extraction. Mining companies have similar conditions to nuclear: upfront high capital costs, work with regulating bodies and experience with radiation. There is a potential for energy neutral phosphate fertilizer production by feeding mined uranium/thorium to a high temperature gas cooled reactor for phosphate rock conversion. The calcination processing of phosphate rock is preferred over flotation; currently, this process is performed by burning of fossil fuels, however requires only heat to be performed. Therefore, it is possible to utilize heat from a reactor to perform this function. Concentrated solar plants may also be able to perform this function and the countries with large phosphate rock reserves also have some of the highest solar potential. At this point in time, this method is not economically competitive; however, may be feasible once SMR prices go down and natural gas prices go up.

The third presentation, entitled *TR_EVOL: A Fuel Cycle Scenario Code for Energy Policy Planning* (P. Romojaro, Centro de Investigaciones Energeticas, Medioambientales y Tecnologicas (CIEMAT)), discussed the need for versatile computation tools or codes for a wide range of new technologies. Transition Evolution Code (TR_EVOL) was developed by CIEMAT to simulate nuclear power plants, fuels, fuel cycle facilities and renewable energy mixes as a boundary condition for diverse nuclear technologies. It consists of a mass module, an economic module, and an uncertainty module. The objective of this study is to identify key variables or indications for implementation of reprocessing in a medium sized light water reactor fleet. Once through, partial reprocessing and full reprocessing options were considered in 40 or 60 year plant lifetimes in Spain. Results showed that reprocessing results in a large reduction in the amount of material for final disposal. Final disposal costs have been calculated for several countries as a verification of the code, with small differences from other codes. TR_EVOL is able to simulate complex nuclear fuel cycles and assess the impact of renewable technologies in fuel cycle, cost, uncertainty and optimization analyses.

The fourth presentation, entitled *Joint Use Modular Plant Program to Support RD&D Needs for Integrated Energy Systems* (S.M. Bragg-Sitton, Idaho National Laboratory), discussed several benefits and challenges facing SMRs. INL is working with several developers of SMR technologies, the majority of which are integral designs. NuScale plants are anticipated to have reduced cost, improve safety, provide economic flexibility and simplify licensing. The Joint Use Modular Plant (JUMP) Program is based at the INL site and coordinated with operating utilities. It will provide the opportunity for research and demonstration utilizing a single module of the proposed NuScale site, however RD&D projects will likely require license amendments. Proposed research pathways include: demonstration of beyond the grid applications of nuclear energy, development testing and demonstration of advanced technologies that could be deployed in SMRs or large LWRs, enablement of nuclear supply chain solutions and evaluation and informing new regulatory approaches. Example opportunities include: a thermal energy delivery system (specific delivery systems, advanced control systems, thermal hydraulics), demonstration of industrial processes that allow modulation (desalination, hydrogen production, carbon conversion), energy storage (electrical, thermal, chemical, load balancing), materials and components testing (fatigue, water chemistry), prototypical fuels testing (advanced technology fuels, higher enrichment fuels), demonstration of advanced in-core or ex-vessel sensors, structural health monitoring (seismic assessment, thermal performance), improved in-vessel measurements to improve understanding of plant performance (thermal performance, multi-module assessment, margin recovery, power and temperature mapping), ex-vessel monitoring (load following support, safety system optimization, flow measurements, support for model predictive control) and verification and validation of advanced codes and module performance. Research projects are being prioritized according to feasibility, stakeholder interests, developing costs and reviewing concepts.

The fifth presentation, entitled *A European Perspective on Nuclear-Renewable Hybrid Energy Systems for Decarbonisation, Load Balancing and Process Heat Applications* (K. Tuček, European Commission Directorate General Joint Research Centre), discussed the role of the European Commission Joint Research Centre in supporting European Union policies with independent evidence. The European Energy Union is based on closely related and mutually reinforced policies, providing supply security, development, sustainability, research and innovation. European Nuclear Illustrative Programme predictions show a decline in nuclear power until 2025, to be reversed by 2030 with extension of existing plant lifetime and installation of new plants. The Strategic Energy Technology Plan sets out to maintain a high level of safety in advanced technologies, maintain competitiveness in fission technologies, complete preparations for a new generation of fission reactors for increased sustainability. The SET-Plan implementation plan is being finalized. Three technical studies were presented. Nuclear power can provide process heat and electricity for production of liquid hydrocarbons. Hybrid systems (wind/biomass/nuclear) were evaluated and shown to reduce the volatility of variable renewable generation by load following nuclear. Small modular reactors show many advantages when compared with large reactors: modularity, smaller unit size, required standby reserve capacity, load following capacity and additional non-electric applications.

The first discussion session focused on emerging nuclear technology and enabling innovations relevant to nuclear–renewable hybrid technology. Several categories of technology development and innovation were identified:

— Reactor technologies (SMRs, Generation IV, flexible operation). For Generation IV reactors, there is a need to identify opportunities for hybridization. Additional capabilities of emerging technologies regarding hybridization, control capability and regulation, are necessary. What developments need to be made on the regulatory framework side? Tightly and loosely coupled systems, impacts on control room interfaces, siting considerations, dry cooling (condenser and turbine effects are coupled), safety aspects and operation. Chemistry impacts for load following.
— Associated technologies (processing, reprocessing, disposal). Extending fuel cycling period for low capacity factor. Heat exchanger development, effects on aging.
— Interfaces and hybridization schemes (diversion connection points, calcination).
— Energy markets.
— Other needs (technical analysis tools). Expansion of IAEA toolkits to hybrid systems and more diverse non-electric applications.

The sixth presentation, by the IAEA (F. Reitsma), provided an overview of IAEA activities related to SMRs including cogeneration, integration with renewables, perceived advantages and potential challenges.

The seventh presentation, by the IAEA (M. Hussain), provided an update on the current status of an in progress IAEA publication on *Options to Enhance Energy Supply Security using Hybrid Energy Systems based on SMRs*.

The eighth presentation, entitled *Nuclear-Renewable Hybrid Energy Systems: Industrial Applications and their Potential Markets* (A. Arif, Pakistan Atomic Energy Commission), discussed the many prospects of nuclear–renewable hybrid energy systems in Pakistan. Several hybrid applications were discussed: an oil shale system, a hydrogen production system, coal based chemical industry, desalination. Potential markets include district heating, pulp paper and food processing, distillation and thermal cracking processes of oil refineries and pharmaceuticals, hydrogen production from water splitting, inorganic minerals production, distillation torrefaction pyrolysis and gasification processes in biofuel refineries, chemical manufacturing, hydrogen production from hydrocarbon, coal gasification for syngas and chemical synthesis, production of glass iron steel and aluminium and production of cement. Pakistan's energy profile was discussed. Pakistan has a low availability of fresh water resources, so desalination is of continuously growing demand. It has a high potential for solar power, which could be tied to nuclear for a desalination hybrid system. The presentation raised several important points for discussion:

— Why get involved in non-nuclear business?
— What is the capacity of non-electric processes?
— What nuclear power plant warranty issues may arise for plant modifications?
— What will be the regulator response?
— What are the nuclear safety and security issues?
— How will market volatility be solved?
— How proven are the relevant technologies?

The second discussion session focused on nuclear–renewable hybrid energy systems for small grids and cogeneration, developing the following points:

— Challenges of small grids are largely related to the need for major flexibilities.
— There are difficulties which arise from mixed energy sources with a large variable renewable mix, and these are pronounced for small grids.

- Nuclear and grid regulator issues may arise in hybrid energy systems. Regulators may need to be educated regarding the market manipulation aspects, possible to address through the long term implications.
- Load following can be put on the cogeneration process (e.g. number of running electrolysis systems).
- Deregulated markets are pushed toward cogeneration.

3. CONCLUSIONS AND RECOMMENDATIONS

The meeting objectives were fully met through participants' contributions with their presentations and focused discussions on the meeting technical sessions. In the meeting, useful information regarding nuclear–renewable hybrid energy systems were shared between Member States. Discussion sessions, held throughout the Technical Meeting, served to develop the following final conclusions and recommendations from the meeting.

Primary drivers for nuclear–renewable hybrid energy system R&D were identified, including (a) project financing, (b) policy and technology options (e.g. carbon mitigation targets, energy security), and (c) energy and power system planning and management for increased reliability and resilience. For each of these, several needs were identified:

(a) Project finance:

- Improvement and enhanced availability of tools and nation-specific datasets for financial calculations;
- Improvement and enhanced availability of tools and nation-specific datasets for grid integration costs;
- Consideration of the limitations and issues regarding discount values especially when calculating life cycle costs;
- Consideration of indirect effects, such as land use changes, on project finance.

(b) Policy and technology options:

- Identification of policy options and benefits or challenges of each policy;
- Identification of technology options and challenges such as development or deployment timeline for meeting carbon mitigation targets;
- Regulatory requirements and development, particularly for assessment of nuclear operational safety, electric utility and industrial process aspects;
- Benefits of energy security and carbon mitigation should be further studied for enhancing public acceptance and policy implementation.

(c) Energy and power system planning and management:

- Enhancement of long term energy planning tools and datasets for power systems, particularly for different system configurations, load shapes and operational datasets;
- Identification of best practices, internalizing of all system costs;
- Identification of means/values/costs to ensure reliability and resilience, especially in liberalized markets;
- Development of tools and techniques for generation and transmission fleet management.

Overall, there is a need for techniques and tools for hybrid systems as well as further R&D related to nuclear power plant flexibility for integrated renewable load following and frequency control. The benefits of nuclear energy for carbon mitigation, ability to provide grid flexibility and safety specific to nuclear–renewable hybrid energy systems may be further communicated to decision makers, stakeholders and the general public.

In addition to these, a number of conclusions were made about the needs for emerging nuclear and other technologies and enabling innovations relevant to nuclear–renewable hybrid energy systems, including:

- Investigation of how renewables might impact reactors from the design phase;

— Identification of operational requirements (e.g. how often and how rapid might power ramping be required);
— Identification of additional capabilities (e.g. load following requirements to control rooms and operator training);
— Investigation of opportunities and potential for advanced technology fuels or advanced reactor designs to be implemented in nuclear–renewable hybrid energy systems;
— Investigation of chemistry impacts on working fluids, including impact on the secondary coolant loop from hybrid systems and other reactor systems;
— Investigation of aging and degradation of valves or other components due to cycling;
— Consideration of hybrid energy system siting;
— Consideration of appropriate licensing safety requirements;
— Consideration of coordinating with other applications such as heat production, hydrogen generation, desalination, calcination, etc.

In response to recommendations from the Technical Meeting, the IAEA initiated the development of a new Nuclear Energy Series publication to discuss the opportunities for nuclear–renewable hybrid energy systems at a high level. This Nuclear Energy Series is expected to be published in 2020.

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ABBREVIATIONS

CCGT	Combined cycle gas turbine
GIF	Generation IV International Forum
HTGR	High temperature gas cooled reactor
INL	Idaho National Laboratory
NREL	National Renewable Energy Laboratory, United States of America
SMR	Small modular reactor
TR_EVOL	Transition Evolution Code

PAPERS PRESENTED AT THE MEETING

SESSION I

NATIONAL APPROACHES

RENEWABLES AND NUCLEAR POWER IN BULGARIA. TENDENCIES AND POSSIBILITIES FOR SUSTAINABLE ENERGY MIX

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Abstract

The development of renewable energy sources is a priority policy of the European Union, including Bulgaria. The country has a diverse power generation mix, including nuclear, thermal power plants and plants using renewables (hydro, wind, solar power plants and biomass).

In the Bulgarian energy mix, base capacities includes nuclear power plant and thermal power plants. Unlike the plants involved in regulation frequencies and exchanges, Kozloduy Nuclear Power Plant (NPP) produces low cost electricity but cannot provide secondary regulation for technological considerations. This creates certain difficulties in covering the balance of the power system in periods of minimal load and in the case of forced production of hydropower plants and wind power plants.

At the moment, Kozloduy NPP is the only nuclear power plant in Bulgaria and the main electricity generating plant providing more than one third of the total annual electricity output. The trend of steady increase in photovoltaic and wind power, which will remain in the near future, leads to greater instability and uncertainty of the power system. This requires the construction of balancing capacities to have the ability to ensure the security of the system.

Building new balancing power plants and expanding existing, characterized by high level of manoeuvrability stop/start and high rate of change of active working power, will overcome the renewable energy system (RES) increase in the energy mix. It should be noted that these measures are related to the increase of both investments for construction and commissioning, as well as increasing balancing costs.

In that connection, there is increasing interest in small modular reactors (SMRs) and their applications. It is reasonable for SMRs to be included in the national power energy capacity, replacing the coal plants and balancing the increase of RES in the future low carbon energy mix. Hydropower can meet flexibility needs at timescales, being complemented by storage technologies.

1. INTRODUCTION

The development of the world and national electricity market is in direction of increasing the share of renewable energy sources. This requires the use of appropriate power plants in the energy mix that are capable in balancing the discrepancies between demand and supply of electricity. The optimal balance between nuclear power plant power and renewable energy is the trend that should follow the formation of the electricity mix in the future.

Ensuring system stability and uninterrupted energy flow by balancing frequency and tension fluctuations is a major challenge for the future. Although there can be no accurate estimates of the power ratio in the future energy mix of Bulgaria, it can be safely said that the trend of increasing the share of renewable energy production will be maintained. As a result, the energy system will face even greater fluctuations stemming from other sources of energy production. These fluctuations could be overcome by additional reserve capacities and flexible production.

2. RENEWABLE TECHNOLOGIES — MAIN FOCUS OF THE NEW ENERGY POLICY

In March 2007, the European Council approved the Energy Policy for Europe and proposed three main objectives for the new policy. Ensuring a secure energy supply for the coming decades is one of the main priorities of the EU's energy policy. The EU has decided that in order to achieve decarbonization of the electricity sector by 2050, it must make a shift to low carbon energy technologies. The competitiveness of European industry, including its nuclear industry in the world and in the European market, must be driven by innovation for safe nuclear technologies. With regard to nuclear power, in March 2007 the European Council concluded that nuclear energy is an important part of the EU's energy mix. This was reaffirmed in February 2011 as stated in the conclusions: "While the swift deployment of infrastructure will support the EU diversification policy due importance should be given to indigenous production, including energy from renewable sources, fossil fuels and, in countries which choose to do so, nuclear energy, within the existing regulatory frame work" [1].

The decision to focus on the interaction of nuclear power and variable renewables results from the rapidly increasing importance of their relationship in the decarbonization of electricity systems. Many countries currently fight to reduce their greenhouse gas emissions. Beyond reductions in absolute consumption, this means substituting fossil fuel based power generation with low carbon technologies such as renewables and nuclear power.

"The decision to focus on the interaction of nuclear power and variable renewables results from the rapidly increasing importance of their relationship in the decarbonising electricity systems… [Many] countries currently strive to reduce their greenhouse gas emissions…Beyond reductions in absolute consumption, this means substituting fossil-fuel based power generation with low-carbon technologies such as renewables or nuclear power.

For instance, the Energy Roadmap of the European Commission (EC) envisions greenhouse gas emissions in 2050 to be at least 80% lower than in 1990, while the electricity sector is supposed to be carbon neutral by that date (EC, 2012) [2]" [4].

The European Commission's 2011 Energy Roadmap set out also four main routes to a more sustainable, competitive and secure energy system in 2050: energy efficiency, renewable energy, nuclear energy, and carbon capture and storage.

At the Paris climate conference (COP21) in December 2015, 195 countries adopted the first ever universal, legally binding global climate deal. The agreement sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2°C. To limit the rise in global mean temperatures to 2°C, the global power sector will need to be virtually decarbonized by mid-century. The only way to do this is with a mix of technologies including nuclear and renewables [3].

Nuclear power is already a mature technology. The barriers to a more rapid deployment are political and social, not technical, nor safety, nor scientific. Nuclear energy currently produces 11% of global electricity, the second largest source of low carbon power after hydro (16%). Globally, nuclear avoids over 2 billion metric tons of CO_2 from being emitted into the atmosphere each year. Hydro is about the same [3].

The limited resource of exhaustible fuels, coupled with climate change, is at the root of the trend towards growth in renewable energy production. The same arguments are valid in favour of stimulating the production of electricity from NPPs, as it is cheap and also low carbon.

"The short term intermittency of wind and solar plants puts great demands on the dispatchable providers of residual demand to vary substantial portions of their load in very short time frames. The ability to follow load will become an increasingly important criterion to choose between different backup technologies" [4]

"All power generation technologies cause system costs. Being connected to the same physical grid and delivering into the same market, they exert impacts on each other as well as on the total load available to satisfy demand at any time. The interdependencies are heightened by the fact that only small amounts of cost efficient storage are available, which means that any buffers for supply and demand coordination are insufficient. Variable renewables such as wind and solar, however, generate system effects that are at least an order of magnitude greater than those caused by dispatchable technologies.

Dispatchable power technologies can provide scalable amounts of electricity to the market at precisely the time when it is needed to cover demand independently, for instance, of meteorological conditions. Gas and coal fired plants are dispatchable, as are nuclear power plants (NPP). There also exist dispatchable renewable technologies such as hydropower, biomass, geothermal power or, to some extent, concentrated solar power (CSP). The latter, however, usually have higher costs and are either in limited supply (hydropower), have other inconvenient side effects (biomass) or can store energy only for a limited period of time. [4]"

"In this context, only nuclear and hydro do not emit any greenhouse gases during electricity generation. Most nuclear power plants operate at stable levels close to full capacity in order to supply baseload electricity. This is not only the simplest operational mode but also economically the most advantageous as long as prices are stable, and it is thus the operational mode that is preferred in most [of the] countries" [4].

3. DECARBONIZATION IN THE OECD COUNTRIES

The decarbonization of electricity generation has strongly contributed to lowering the carbon intensity of the energy mix in OECD (Organisation for Economic Co-operation and Development) — 10% fall was recorded between 1990 and 2016. Starting from similar levels in 1990, the three regions have moved at different rates: while levels in Asia Oceania, strongly impacted by the Fukushima accident, were 2% higher in 2016, those for Europe were 16% lower than in 1990 and those of the Americas 9% lower [3].

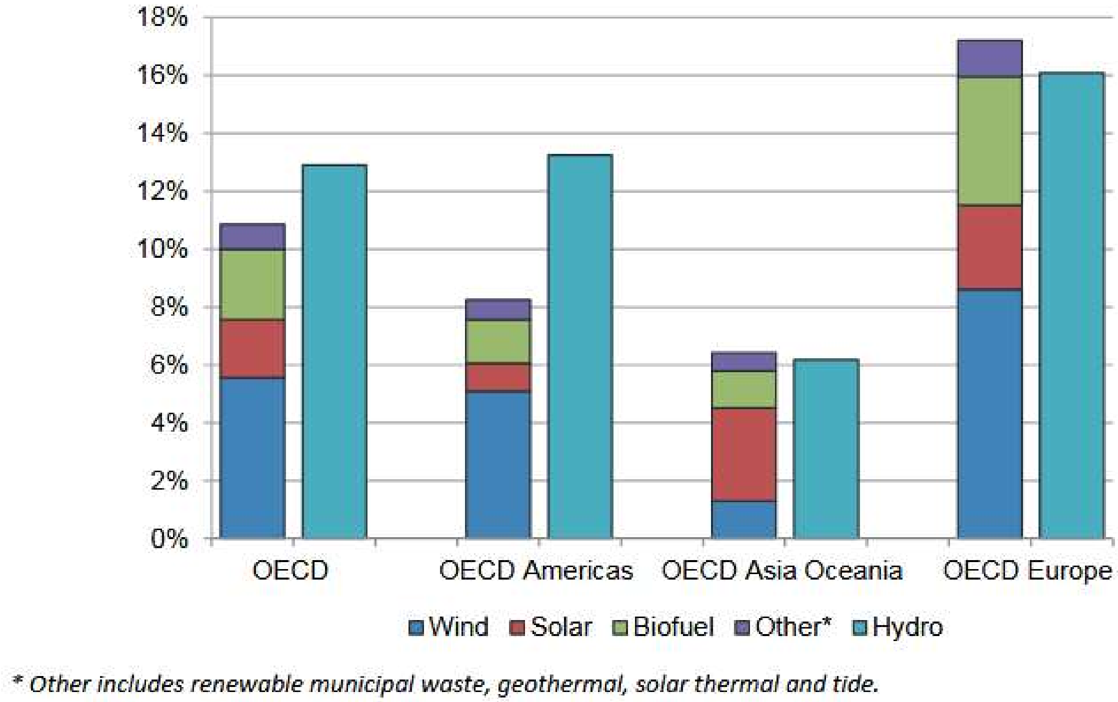

FIG. 1. OECD electricity generation from renewables: shares in 2016 by region [4].

Electricity generation is the sector with the highest decarbonization rates since 2000 for a variety of reasons. Electricity production, which increased by 2.5% each year on average between 1990 and 2000, has subsequently seen reduced growth over time, including almost flat trends in recent years (+0.1%/yr between 2010 and 2016). The coal to gas switch and related increase in generation efficiency significantly acted to lower emissions from 2000 onwards. Additionally, the effect strengthened for the further penetration of renewable sources, which lowered the share of electricity output from fossil fuels by 5% over the last six years.

"In future low carbon electricity systems, nuclear energy will coexist with evermore significant amounts of renewable energies. Given that hydropower is already largely exploited in many OECD countries, the most important reservoir of renewable energy is constituted by wind and solar power, which are characterised by intermittent production due to irregular and uncertain weather patterns. [4]"

Lower carbon intensity of electricity generation has been one of the driving factors for the OECD emissions reductions over time (-8% between 2000 and 2016). However, lowered energy intensity has been the largest factor, as TPES/GDP decreased by 25% since 2000, linked to energy efficiency improvements among other factors.

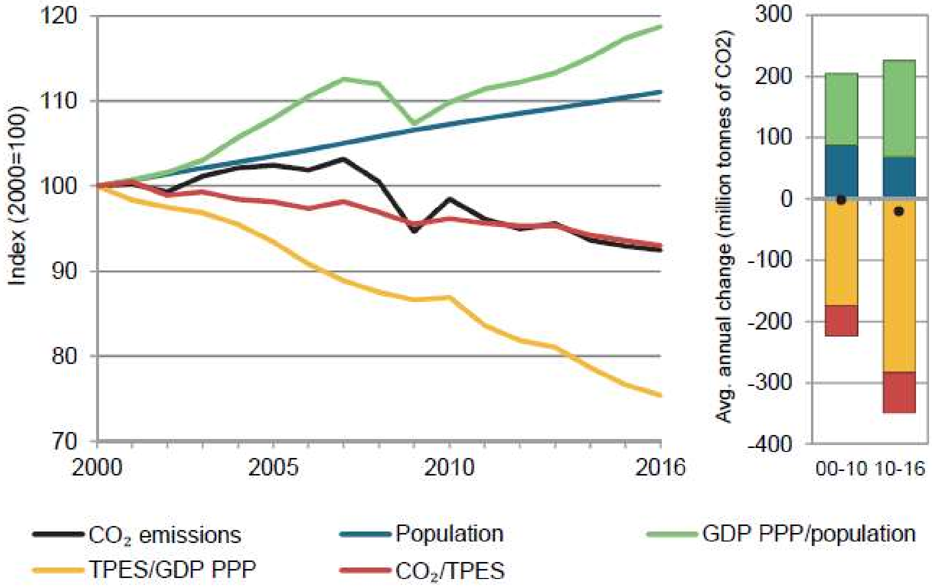

FIG. 2. OECD CO_2 emissions and drivers [4].

Those two combined effects have allowed a very significant decoupling of emissions from GDP growth: while GDP increased by over 30%, CO_2 emissions in OECD decreased by 8% between 2000 and 2016. At the country level, the strongest decreases in the last sixteen years have occurred in Denmark (-34%) and the UK (-29%); but several OECD countries have experienced significant increases, such as Australia (17%), Mexico (24%), Republic of Korea (36%), Turkey (68%) and Chile (75%).

“In order to increase the share of renewable generation, most of it variable wind and solar generation, OECD governments are promoting their use, frequently through fixed feed-in tariffs (FITs). These policies can lead to substantial changes in the structure of generating capacity” [4].

4. ENERGY MIX. RENEWABLE ENERGY SOURCES AND NUCLEAR POWER DEVELOPMENT IN BULGARIA

4.1. Energy mix in Bulgaria

The contribution of RES to the development of the internal energy market contributes to the realization of the main priorities of the national energy policy related to:

- — Limiting the country's dependence on imported energy resources;
- — Mitigating the effects of climate change;
- — Development of a competitive energy market and policy aimed at securing the energy needs and protecting the interests of consumers;
- — Increasing energy efficiency [5].

Bulgaria has a diverse power generation mix, including nuclear, thermal power plants and plants using renewables (hydro, wind, solar power plants and biomass). Total installed capacity of all electricity generation types in the country in 2016 was 12 701 MW. Available generation capacity (without RES generators) to the annual maximum amounts at 7608 MW, RES generators being excluded from the available generation capacity as their generation is intermittent and difficult to forecast and dispatch. Absolute maximum load was realized on 4 Jan. at 7 p.m. (7105 MW) and the absolute minimum load was realized on 24 May at 4 a.m. (2662 MW).

Total installed capacity of wind energy in 2016 amounted to 701 MW, with an annual production of about 1 426 696 MWh. In 2016, the installed capacity of photovoltaic (PV) plants was about 1043 MW with production of 1 392 338 MWh.

Key energy indicators for Bulgaria in 2016 are provided in Table 1 [6].

TABLE 1. KEY ENERGY INDICATORS, BULGARIA, 2016

PRODUCTION SOURCE	ELECTRICITY (GWh)	HEAT (TJ)
Coal	19 364	16 811
Oil	318	6253
Gas	2053	21 856
Biofuels	353	743
Waste	0	0
Nuclear	15 776	612
Hydro	4568	0
Geothermal	0	0
Solar PV	1392	0
Solar thermal	0	0
Wind	1426	0
Tide	0	0
Other sources	34	1927
Total production	45 277	48 202
Imports	4568	0
Exports	-10 940	0
Domestic supply	38 905	48 202
Statistical differences	-41	31
Transformation	0	673
Electricity plants	0	673
Heat plants	0	0
Energy industry own use	6389	8445
Losses	3577	6331
Final consumption	28 898	32 784
Industry	8910	12 717
Transport	354	0
Residential	10 733	13 591
Commercial and public services	8678	6144
Agriculture / forestry	221	332
Fishing	2	0
Other non-specified	0	0

In the Bulgarian energy mix base capacities includes nuclear power plant (NPP) and thermal power plants (TPP). Unlike the plants involved in the regulation frequencies and exchanges, Kozloduy NPP produces low cost electricity, but is not possible to provide secondary regulation for technological considerations. This creates certain difficulties in covering the balance of the power system in periods they are on minimal load and in the case of forced production of hydropower plants (HPP) and wind power plants (WPP) [7].

The current energy mix of the country can be classified as highly dependent on external energy resources: Bulgaria provides 70% of its gross consumption through imports. The dependence on imports of natural gas, crude oil and nuclear fuel is mainly from Russian Federation.

There is a significant development of the electricity market in the country through introducing a market within the day. Thus, when supplying electricity in the country significantly exceeds the demand, the different types of segments of the regional market will provide an additional opportunity for delivery of electric power in order to minimize costs and increase the cost profits [8].

Although in the last few years there has been a significant decrease, the energy intensity of the Bulgarian economy continues to be the highest in the EU, sometimes higher than the average. Bulgaria ranks first in energy intensity in EU 27, i.e. the Bulgarian economy consumes the greatest amount of energy needed to produce a unit of GDP. Despite the long term trend of improving the energy efficiency of the Bulgarian economy, measured by the total energy efficiency index, in 2011 Bulgaria ranks last in energy efficiency at EU 27 level, which is one of the factors limiting the productivity and competitiveness of enterprises in Bulgaria.

4.2. Electricity generation from renewables by source

The development of renewable energy sources is a priority policy of the European Union, including Bulgaria. As the potential of RES in each Member State is different, both quantitatively and as a mix, each country draws up its own plan to achieve its national targets as set out in Directive 2009/28/EC [9].

The National Indicative Target for 2010 defined in the Accession Treaty of the Republic of Bulgaria to the European Union and Directive 2001/77/EC is 11% of the gross domestic electricity consumption to be produced from RES and the target for the consumption of liquid biofuels according to Directive 2003/30/EC is to reach 5.75% of petrol and diesel used in transport. Bulgaria, as a full member of the European Union, takes its share in achieving the objective — at least 16% of RES in gross final energy consumption in 2020. This requirement also covers the 10% share of RES in transport, which is mandatory for all Member States. Achieving these national targets for Bulgaria requires a targeted policy to promote the production of energy from RES.

According to Eurostat, for the period 2005–2012 the share of energy from RES in the structure of gross final energy consumption has increased by up to 16.3% in 2012, which is above the EU 28 average — 14.1%. By this in practice the national objective of 16% share of energy from RES in the gross energy end consumption by 2020 is achieved. The figure for 2016 is 18.8%.

Hydroelectric power has been developing in the country for more than 100 years, as the installed capacity is more than 2000 MW without pumps, but the resource is relatively limited. The annual average water resource of a citizen in the country is about 2300–2400 cubic meters, and a fraction of it consumed is from 800 to 1000 cubic meters. With its available water resources, Bulgaria ranks last among the countries on the Balkan Peninsula and among the five poorest countries in water resources in Europe together with Poland, Belgium, Belgium and Cyprus [9].

Under the current energy mix in Bulgaria and because of the specifics of the technology, HPPs are mainly used to ensure peak consumption and to quickly offset imbalances. Additional obstacles arise from the fact that priority in the use of water resources is the satisfaction of the population's drinking water needs. A second priority is the necessary quantities for irrigation in agriculture, the third — the industrial water demand needs, and only then is hydropower. In the future, the water deficit is expected to deepen, which will become a very serious social, economic and environmental problem for the country.[9]

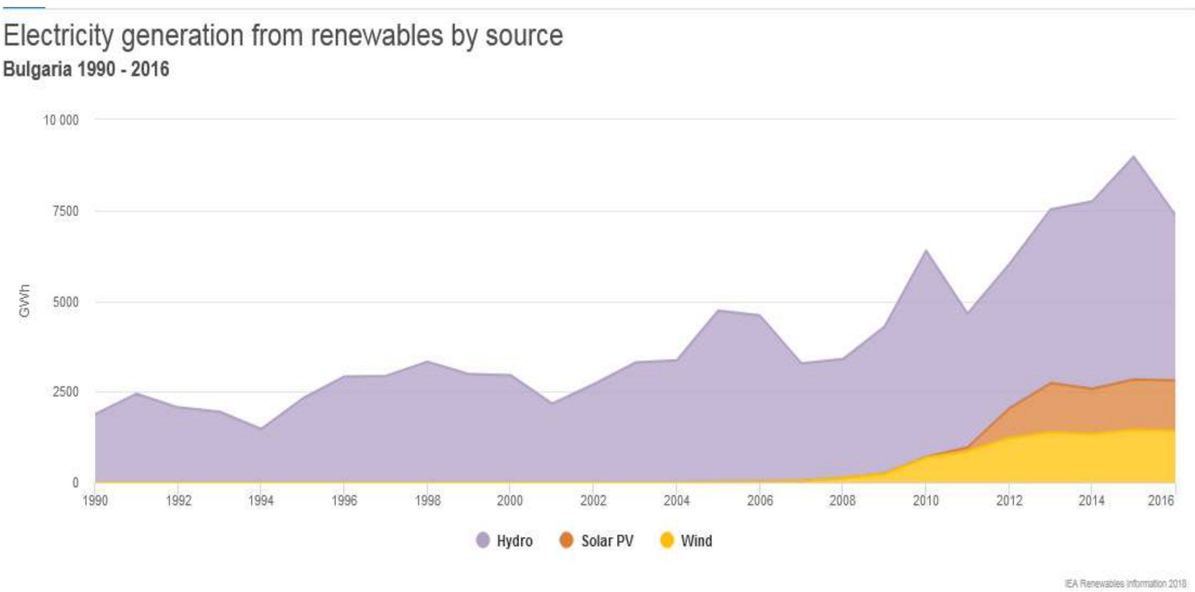

FIG. 3. Electricity generation from renewables by source electricity generation from renewables by source [7].

Photovoltaic technologies are advancing extremely fast in terms of technology, efficiency and cost. Bulgaria has a serious theoretical potential for solar power generation. The potential for its use by household users is enormous. This is particularly true in the current falling cost of equipment and the cost of household electricity [9]. The accelerated penetration of PHPP causes serious problems with the frequency regulation of the power system in the different parts of the country.

In Bulgaria, the efficiency of biomass resource utilization is low. Fossil wood harvesting lacks sustainable planning, thus limiting the available biomass potential, restoring time and reducing the beneficial impact of the increased use of RES. Basic criteria for the profitability of biomass and for increasing the potential used are transport costs and collection costs. As higher these costs are, the lower the profitability of production is [9].

In recent years, wind power technologies offer one the lowest cost of installed power compared to other renewable energy sources. The technological capabilities of the new generation of wind turbines are increasing, allowing efficient operation at low winds. Even in areas where, according to preliminary data, there is not enough wind, new technologies and more advanced wind turbines would allow successful projects [9].

At present, potential raw materials for biogas production are being used incompletely. The separate waste collection and recycling system in Bulgaria is still not functioning properly — about 85% of the generated waste is transported to the landfill, while at the same time about 52% of the total waste is biodegradable. For this reason, much of the biodegradable waste falls into the landfill [9].

According to a study by the Geothermal Energy Association for EBRD, Bulgaria's geothermal potential for energy generation is estimated at around 200 MW. This potential can hardly be used to produce electricity due to the relatively low temperature of the available deposits [9].

Some technologies for the recovery of renewable energy sources, such as electricity generation from seas, tides and waves, geothermal sources, concentrated slush, etc., are still underdeveloped, with low efficiency and the cost of installing them are unreasonably high [9].

RES electricity generation over three years (2014–2016) is summarized and presented in Table 2 [10]. Table 3 shows detailed information for the year 2016 [10].

From the data presented, it is clear that the energy produced by HPP has the largest share compared to other renewable technologies. HPPs are also the only renewable source that provides the balance between supply and demand fluctuations. Considering the EU's renewable energy policy, as well as the increased commitments on the share of renewable energy in Member States' gross consumption, this regulatory function will become increasingly important in the future. This is another reason to focus on the usefulness of HPPs in terms of ensuring the stability and security of the system.

TABLE 2. ELECTRICITY GENERATION BY RES IN BULGARIA

RENEWABLE ENERGY SOURCE	PRODUCED ELECTRICITY (MWh)		
	2014	2015	2016
Renewable natural gas	2495	5027	19 395
Biomass	123 684	136 855	269 827
Hydro	4 579 490	5 718 358	4 438 304
Wind	1 329 743	1 087 542	1 424 970
Waste Water Gas	1195	1617	3009
Waste gas	331	403	385
Solar	1 252 523	1 128 896	1 381 058
TOTAL	7 289 461	8 077 081	7 536 948

TABLE 3. PRODUCED ELECTRICITY BY RES, BULGARIA 2016

RENEWABLE ENERGY SOURCE	INSTALLED CAPACITY (MW)	PRODUCED ELECTRICITY (MWh)	AVERAGE COST (BGN*/MWh)
Renewable natural gas	3	19 395	452.1
Biomass	51	269 827	407.1
Hydro	3327	4 438 304	74.5
Wind	698	1 424 970	174.7
Waste water gas	3	3009	120.6
Waste gas	1	385	226.1
Solar	1027	1 381 058	494.8

*1 EUR =1.95583 BGN

On the basis of the above, it can be summarized that HPPs have the greatest advantage in terms of both the share of electricity produced and the lowest cost to society.

4.3. Nuclear power development

The nuclear development of Bulgaria started after the Geneva conference Atoms for Peace in 1956. The first step was the construction and the start of operation of IRT-2000 research reactor. Later, in 1966, an agreement was signed with the Soviet Union to deliver commercial reactors for electricity production. The first two units, which are a typical WWER 440/230 model, were built and put into operation for a period of less than 5 years. The second pair of reactors was completed and connected to the grid in 1980 and 1982 accordingly. The further increase in the electricity demand resulted in the construction of additional two units of 1000 MW each WWER-1000/320. A second site was chosen in the early eighties near to the city of Belene. The site was prepared with the entire necessary infrastructure to host six 1000 MW units. Completion of the first unit reached about 40% on construction, and 80% on delivery of equipment, when due to lack of financial resources the construction was frozen in 1990. In 2005 the Council of Ministers decided to recommence the Belene NPP project. In 2006 the Russian company Atomstroyexport was chosen as a main contractor but in 2012 the Council of Ministers took another decision repealing all previous decisions related to the construction of the Belene Nuclear Power Plant.

In April 2012, the Council of Ministers approved in principle the construction of new capacity at Kozloduy. The construction of new power plant, generation III or III+ light water reactor technology with installed capacity around 1200 MW is the investment proposal, which will be realized strictly in accordance with the legislation in force in the area of nuclear safety, the requirements of the European exploitation organizations of nuclear power plants with light water reactors, as well as the latest requirements of the International Atomic Energy Agency (IAEA) regarding the construction of new nuclear capacity.

In June 2016, the National Electric Company (NEC) was sued to pay 550 million euro to the Russian company Atomstroyexport for the lost arbitrage regarding the cancelled Bulgarian project NPP Belene, which is only the cost for the already manufactured equipment — two nuclear reactors and equipment.

At the moment Kozloduy NPP is the only nuclear power plant in Bulgaria and the main electricity generating plant providing more than one third of the total annual electricity output of the country. This determines the significant position the company holds — being a factor of economic sustainability both nationally and regionally. Kozloduy NPP generates clean and the cheapest electricity in the country, thus ensuring and maintaining affordable price of electricity for Bulgarian end consumers.

5. FLEXIBILITY OF BULGARIAN ELETRICITY SYSTEM

Final energy consumption follows the curve of the country's economic development. There is a scenario where energy consumption is not dependent on GDP, but this would happen if high cost products are produced in the country that do not require a lot of energy for their production (for example, computer software). In this respect, economic development is tied to increasing activity in all sectors of the economy and consequently increasing energy consumption in manufacturing, services, transport and agriculture. Additionally, with more intense development, the achievement of planned sustainable growth and an increase in living standards, a further increase in household electricity consumption is expected.

Energy efficiency and carbon free policies as well as the introduction of new technologies, created a mix of factors influencing differently on the current and future electricity market in the country.

The only possible long term expert estimates are based on macroeconomic forecasts, as Bulgaria lacks representative forecasts for the development the economic sectors. As official sources of macroeconomic forecasts are accepted those of the European Commission until 2050 — "EU Reference Scenario 2016 – Energy, transport and GHG emissions - Trends to 2050" [11].

According to the prognosis, Bulgarian electricity sector will need 2400 MW installed and operating nuclear capacity in 2045 year as this nuclear capacity is going to substitute the power from units 5 & 6 of Kozloduy NPP. In 2050 the renewable energy resources installed capacity is expected to be doubled in comparison with 2020 as they will get 60% from the installed capacity in the national energy mix. This type of investment is often associated with significant investment in infrastructure and additional costs of integration into the existing power grid.

Maintaining a balance between production and consumption as well as ensuring safe, secure and economical electricity supply within the voltage and frequency tolerances are basic principles in the management of the power system. The rapid increase in the share of renewable generating capacity installed in recent years, coupled with their unpredictability and their inability to self-balance, creates significant difficulties in managing the power mix to cover the loads in the system.

TABLE 4. "EU REFERENCE SCENARIO 2016 – ENERGY, TRANSPORT AND GHG EMISSIONS - TRENDS TO 2050"

YEAR	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
POPULATION (MILLION)	8	8	7	7	7	7	6	6	6	6	6
GDP (000 M€13)	25	33	38	40	45	50	53	57	61	64	67
GROSS ELECTRICITY BY SOURCE (GWh)	40 646	43 972	46 017	48 843	48 789	49 938	50 487	54 352	53 603	53 275	56 749
Nuclear energy	18 178	18 653	15 249	15 662	15 326	15 326	15 326	15 326	15 326	20 148	20 148
Solids	16 941	18 458	22 606	23 317	22 690	18 563	17 456	15 856	13 555	8180	11 972
Oil (including refinery gas)	661	606	393	440	70	63	0	62	0	0	0
Gas (including derived gases)	2178	1896	1967	3035	3873	4408	4120	8521	8243	6758	5230
Biomass waste	15	17	49	54	164	463	455	1063	1787	1985	2085
Hydro (pumping excluded)	2673	4337	5057	4061	4331	4235	4218	4220	4223	4223	4227
Wind	0	5	681	1144	1183	5050	5589	5667	5921	7307	7518
Solar	0	0	15	1129	1152	1829	3323	3636	4548	4674	5570
Geothermal and other renewables	0	0	0	0	0	0	0	0	0	0	0
Other fuels (hydrogen, methanol)	0	0	0	0	0	0	0	0	0	0	0
NET GENERATION CAPACITY (MW)	10 471	10 635	9943	11 968	11 812	12 479	13 488	13 114	13 110	14 069	15 293
Nuclear energy	3610	2765	1920	1920	1920	1920	1920	1920	1920	2400	2400
Renewable energy	1016	1992	2697	4081	4110	5832	7032	7271	7923	8346	9019
Hydro (pumping excluded)	1016	1984	2184	2338	2338	2338	2338	2338	2338	2338	2338
Wind	0	8	488	691	703	1954	2122	2146	2197	2535	2599
Solar	0	0	25	1052	1069	1541	2572	2787	3388	3473	4082
Other renewables (tidal, etc.)	0	0	0	0	0	0	0	0	0	0	0
Thermal power	5845	5878	5326	5967	5782	4726	4536	3924	3267	3323	3874
Of which cogeneration units	1129	1191	1017	1814	1704	1653	1518	1143	1016	1140	1146
Of which CCS units	0	0	0	0	0	0	0	0	0	0	990
Solids fired	5100	5100	4703	5313	4819	3501	3391	2379	1799	1590	2179
Gas fired	689	737	607	626	910	1129	1043	1433	1271	1517	1478
Oil fired	57	42	13	13	2	2	2	0	0	0	0
Biomass waste fired	0	0	3	15	51	94	101	112	197	216	217
Hydrogen plants	0	0	0	0	0	0	0	0	0	0	0
Geothermal heat	0	0	0	0	0	0	0	0	0	0	0
Avg. load factor of net power capacity (%)	39.9	42.8	47.7	42.3	43.3	42.7	40.1	44.7	44.3	41.3	39.3

This requires provision of capacities with additional high voltage balancing reserve capacities to cover the power generation needs depending on the fluctuations in the operation of the RES. In the composition of the base capacities are NPP and TPP.

Unlike the plants involved in the regulation frequencies and exchanges Bulgarian NPP — Kozloduy NPP produces low cost electricity, but not may provide secondary regulation for technological considerations. This creates certain difficulties in covering the balance of the power system in periods with minimal load and in the case of forced production of HPP and WPP.

These difficulties occurred in the spring of the last three years when it was required Kozloduy NPP's operating capacity to be limited due to the greatest concentration in complex dams and the forced work of HPP because of spring high water. With the accelerated penetration of RES and lack of industrial load in the country, the role of NPPs power generation over certain periods of the year will increase. In addition, the usability of Pumps ‘Chaira’ in pump mode is limited by 4 to 6 hours at maximum power and optimum level of the lower equalizer. Increasing the volume of the lower equalizer by connecting it to the future Yadenitsa dam would greatly increase the usability of pump storage hydro power plant (PSHPP) in the individual reversible regimes, and hence relieving partly the problem of balancing RES, respectively the limitation of conventional capacities in low load periods

In Bulgarian power system and market, priority generation capacities are highly efficient cogeneration plants, as well as power plants from RES (WPP, PHPP, biomass, etc.). Included in this group are also hydroelectric power plants, as well as thermal plants with a ‘take or pay’ term on long term contracts.

The share of all these capacities is getting bigger and bigger and it is more difficult to regulate the frequency and the power exchanges. This requires special attention to be paid to the planning of power balances and adjusting capacities.

Additionally, energy consumption has large daily fluctuations. For example, on January 11, 2018, during the early hours of the night, consumption was only 5600 megawatts, but in the evening at 7:00 p.m., it reaches 7680 MW. The difference is over 2000 MW, and although night tariff for electricity is much cheaper than the daily rate, it is not possible to balance the system.

6. MEASURES FOR ENSURING SUCURITY AND EFFECTIVENESS OF THE BULGARIAN POWER SYSTEM

The trend of steady increase in photovoltaic and wind power, which will remain in the near future, leads to greater instability and uncertainty of the power system. This, in turn, requires the construction of balancing capacities to have the ability to ensure the security of the system.

With rising variable shares of total electricity generation, the need for different types of flexibility in the power system increases. This is due to the mismatch between variable generation and consumption patterns, and to the fact that variable generation can ramp up and down quickly. Specifically, there can be both an excess and a shortage of generation from variable renewables (depending mainly on weather conditions). Flexibility needs include ensuring stability (very short term), power ramping within a few minutes, and energy provision over days or weeks. There is in particular a need to store surplus electricity and to address security of supply concerns at times of low generation from variable renewables. Different energy storage technologies can take different roles in the power system.

Building new balancing power plants and expanding existing, characterized by high level of manoeuvrability stop/start and high rate of change of active working power will overcome the RES increase in the energy mix. It should be noted that these measures are related to the increase of both investments for construction and commissioning, as well as increasing the balancing costs.

In that connection there is increasing interest in small modular reactors (SMRs) and their applications. SMRs could fulfil the need of flexible power generation for a wider range of users and applications, including replacing aging fossil power plants, providing cogeneration for developing countries with small electricity grids, remote and off grid areas, and enabling hybrid nuclear/renewables energy systems. Most of the SMR designs adopt advanced or even inherent safety features and are deployable either as a single or multi module plant. SMRs are under development for all principal reactor lines:

water cooled reactors, high temperature gas cooled reactors, liquid metal, sodium and gas cooled reactors with fast neutron spectrum, and molten salt reactors [12].

Many SMRs are envisioned for niche electricity or energy markets where large reactors would not be viable. It is reasonable SMRs to be included in the national power energy capacity, replacing the coal plants and balancing the increase of RES in the future low carbon energy mix [12].

Hydropower can meet flexibility needs at timescales, being complemented by storage technologies. Pumped storage hydropower plants can provide flexibility services to the system. Hydropower plants can ramp up and down quickly to respond to short term system needs and provide services for voltage and frequency stability. They can also serve longer term flexibility needs based on their energy storage capacity. Hydropower can address congestions at both transmission and distribution level to some extent.

Some investments should be done in the hydropower sector of the country. For example, the increase in the volume of the lower equalizer by connecting it with the future Yadenitsa dam has greatly increased the usability of pump storage hydro power plant (PSHPP) 'Chaira' — the most perspective national hydro power project, in the individual reversible regimes, and hence relieving the problem of balancing RES, respectively limitation of conventional capacities in low load periods.

It should not be forgotten that Bulgaria is among the five poorest countries in water resources in Europe which makes the use of PSHPPs for managing flexibility of the country's energy system not so reliable.

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HYBRID NUCLEAR-RENEWABLE ENERGY SYSTEMS FOR SUSTAINABILITY AND CLIMATE CHANGE MITIGATION IN TURKEY

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Abstract

In Turkey, renewable energy potential is very high, but only about 1/3 of total energy production and 1/10 of total energy consumption are represented by renewables. As a result of the increasing energy consumption of Turkey, carbon dioxide & greenhouse gas emissions are increasing. Therefore, it is important to protect the environment by reducing emissions of greenhouse gases. The geographical location of Turkey leads to use wind, biomass, hydropower, geothermal and solar energies with the combination of other energy technologies for higher performance and better climate change mitigation. Turkey has begun its nuclear program in order to respond to the growing electricity demand, and renewable energies can be effectively used with the nuclear systems for hybridization. Hybrid nuclear–renewable energy systems are combined systems of renewable energy and nuclear reactors to reach better sustainability, reduced greenhouse gas emissions and grid flexibility. In this study, Turkey's greenhouse gas information, renewable energy sources/fields/installations, and planned nuclear power plants are investigated. Also, the possible hybridization of nuclear and renewable energies considering the solar and wind renewable energy fields and potentials are studied. In this regard, a hybrid nuclear–solar tower collector energy system, a hybrid nuclear–solar parabolic through collector energy system and a hybrid nuclear–wind energy system are investigated for possible installations in Turkey. It is seen that all of these three options can be effectively constructed in Turkey due to high solar and wind potentials. The best hybrid nuclear–wind energy system location(s) can be the Mediterranean Sea and/or Marmara Sea coasts of Turkey, while the best hybrid nuclear–solar energy system locations are the Aegean Sea coast and/or the Mediterranean Sea coasts of Turkey for sustainable and environmentally friendly power production.

1. INTRODUCTION

Energy is essential to reach sustainable societies and to supply their demands continuously and in an environmentally friendly manner. It is expected that the human population will reach 8.5 billion by 2030 and this increase will lead to energy consumption increasing by 34% by 2035 [1,2]. Fossil fuels are major energy sources used to supply the global energy requirement. Oil, coal and natural gas fossil fuels are the dominant primary energy suppliers of the world. They are finite and mostly based in unstable regions. Thus, energy security becomes a primary concern. Also, fossil fuels are sources of greenhouse gases and contribute to climate change [3]. Therefore, sustainable global energy demand can be supplied by nuclear and renewable energy sources. Both nuclear and renewable energies contribute to decarbonization and also mitigate ecological degradation [4]. Renewable energy sources such as wind, biomass, solar and hydropower are obtained from replenished natural processes. Renewable energies are clean, primary, inexhaustible and domestic sources [5,6], while nuclear energy is efficient and reliable energy which is obtained by advanced technology [7].

There are 450 active nuclear power plants in 31 countries in the world today and most of them are in the USA and Europe. In 2017, 11% of electricity generation in the world, which is equivalent to 2477 TWh, was produced by nuclear power plants and there are new 59 nuclear reactor constructions in 18 countries to increase this share [8,9]. There are some drawbacks for nuclear and renewable energies. Nuclear energy has risks such as disposal of nuclear wastes, and nuclear reactor meltdown which results in both environmental and social impacts. On the other hand, renewable energy depends on geographical and climatic conditions [2].

Considering the advantages of nuclear and renewable energy sources, renewable–nuclear based hybrid energy options can be proposed for a better sustainable, environmental future. A hybrid system is a single, physically coupled facility that takes two or more energy resources as inputs and produces two or more products, with at least one being an energy commodity such as electricity or transportation fuel [10,11]. There are some benefits to using renewable and nuclear energies together: (a) greenhouse gas emissions can be reduced, (b) efficiency of power generation can be increased, (c) reliability of the system can be increased, and (d) sustainable and continuous energy generation can be achieved [12].

In Turkey, the renewable energy potential is very high, but only about 1/3 of total energy production and 1/10 of total energy consumption are represented by renewables. As a result of the increasing energy consumption of Turkey, carbon dioxide and greenhouse gas emissions are increasing. Therefore, it is important to protect the environment by reducing emission of greenhouse gases. The geographical location of Turkey leads to use wind, biomass, hydropower, geothermal and solar energies with the combination of other energy technologies for higher performance and better climate change mitigation. Turkey has begun its nuclear program in order to respond to the growing electricity demand, and renewable energies can be effectively used with the nuclear systems for hybridization [13]. In this study, hybrid nuclear–renewable (solar and wind) energy systems for sustainability and climate change mitigation in Turkey are investigated.

2. ENERGY SOURCES IN TURKEY

Turkey is between 36º–42º north latitude and 26º–45º east longitude geographical coordinates with 814 578 km^2 area and a population over 80 million. Turkey is located between the continents of Europe and Asia and surrounded by seas on three sides. The economy and population of Turkey are increasing and energy demand is increasing correspondingly. The energy demand of Turkey mostly depends on imported energy sources. Therefore, alternative domestic energy sources such as renewable energy and nuclear energy have been considered as part of the energy policies of Turkey [14].

Turkey is the 6th largest electricity market in Europe with 85.2 GW installed power, the 5th largest energy consumer in Europe with 137.9 MTOE consumption per year, the 4th largest gas consumer in Europe with 53.4 billion m^3 consumption and among the world's largest growing renewable energy markets. Turkey also has geographic proximity to 73% of world's oil and gas reserves. Turkey's installed electricity capacity per energy sources in 2017 are given in Fig. 1 while Turkey's installed electricity capacity and generation in 2017 are tabulated in Table 1 [15,16].

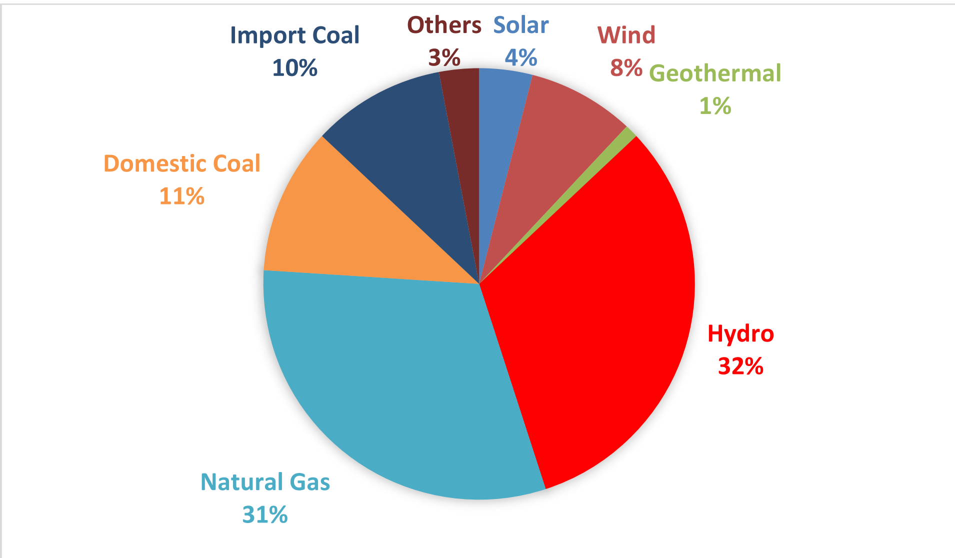

FIG 1. Turkey's installed electricity capacity per energy sources in 2017 [15,16].

TABLE 1. TURKEY'S INSTALLED ELECTRICITY CAPACITY AND GENERATION IN 2017

RESOURCES	INSTALLED CAPACITY (MW)	SHARE (%)	GENERATION (TWh)	GENERATION SHARE (%)
Renewables	11 000	13	26.5	10
Natural gas	26 638	31	108.1	37
Hydraulic	27 273	32	58.3	20
Domestic coal	9872	11	44	15
Import coal	8794	10	51.1	17
Other	1623	3	7.5	1
Total	85 200	100	295	100

As is seen in Fig. 1 and Table 1, renewable energies had 13% installed capacity and 10% generation shares among resources, while fossil fuels had largest shares among the energy sources for electricity installation and generation in Turkey in 2017. For a more sustainable environment and decarbonization, fossil fuels' share is planned to be reduced and new renewable energy installations and nuclear power plant constructions began in 2018.

Turkey's strategic plan on energy until 2019 is to ensure energy supply security, quality and affordability across the population while ensuring environmental sustainability. In this regard, (a) decreasing share of natural gas below 30% in electricity generation, (b) increasing gas storage to 10% of the consumption, (c) increasing electricity generation from local coal to 60 TWh, (d) utilization of the renewable energy potential in a cost effective manner with 30% renewables, and (e) increasing hydro capacity to 32 GW, wind capacity to 10 GW and solar capacity to 3 GW are considered in the strategy [15].

Turkey's vision for 2023 envisages targets for the energy sector in Turkey as follows [15]:

- Raising the total installed power capacity to 120 GW;
- Increasing the share of renewables to 30%;
- Maximizing the use of hydropower;
- Increasing the installed capacity based on wind power to 20 000 MW;
- Installing power plants that will provide 1000 MW of geothermal and 5000 MW of solar energy;
- Extending the length of transmission lines to 60 717 km;
- Reaching a power distribution unit capacity of 158 460 MVA;
- Extending the use of smart grids;
- Raising the natural gas storage capacity to more than 11 billion m^3;
- Commissioning nuclear power plants;
- Increasing the coal fired installed capacity from the current level of 17.3 GW to 30 GW.

As explained in Turkey's 2019 energy plan and 2023 energy vision, renewable energy capacity and the number of nuclear power plants will be increased. The energy installation plan of Turkey until 2023 can be seen in Fig. 2.

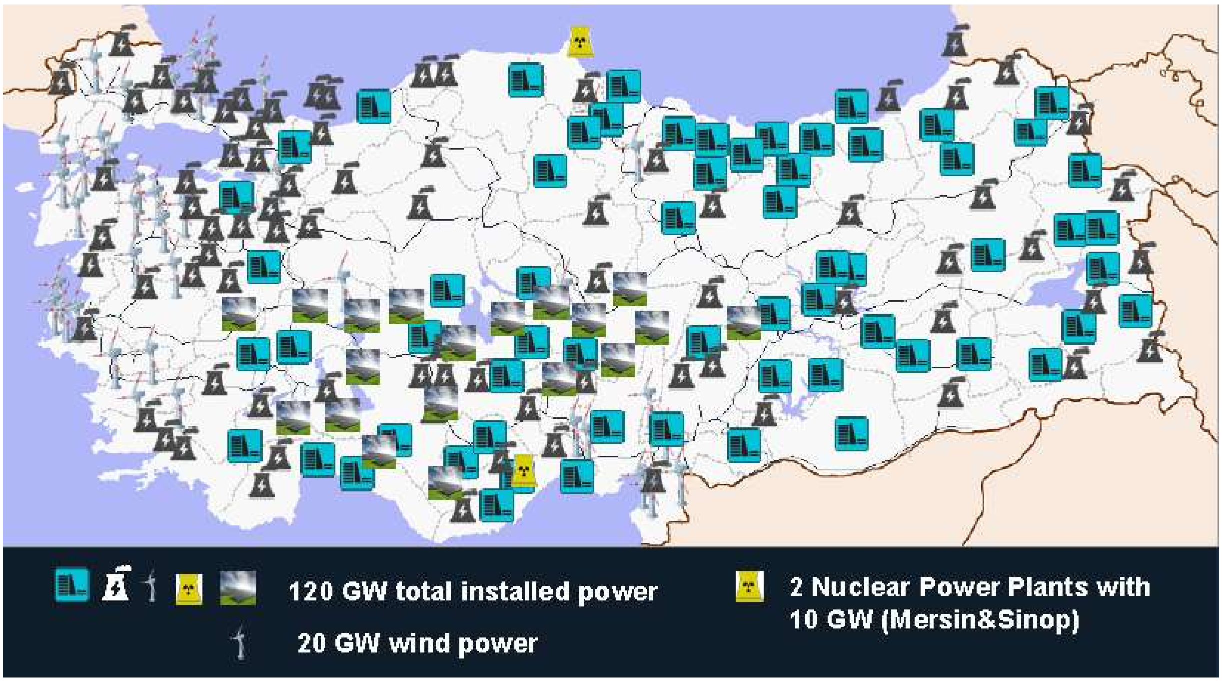

FIG 2. Energy installation plan of Turkey until 2023 [15].

2.1. Renewable energy in Turkey

The renewable energy potential of Turkey is very high due to its geographical location and utilization of this potential is increasing day after day. As of the 60th day in 2018, wind (6580 MW) and hydro (27 456 MW) resources were major renewable energy suppliers. Solar, geothermal and biomass energy resources also contribute to the total capacity with increasing rates compared to previous years [17].

Turkey has a suitable potential for the utilization of solar energy as it lies in a sunny belt location. Turkey's total annual insolation time is 2741 hours (a total of 7.5 hours per day), and the total solar energy derived per year is 1527 kWh/m^2 per year (total 4.18 kWh/m^2 per day). The total established solar collector area within Turkey as of 2017 was calculated as being close to 20 000 000 m^2. Also, in 2017, close to 823 000 TEP (Tonnes Equivalent to Petrol) heat energy was produced using solar collectors. As of the end of 2018, the total installed capacity of PV solar power plants was 5063 MW, with 4981.2 MW unlicensed and 81.8 MW licensed [18].

Turkey has an annual wind speed of 8.5 m/s and higher. As a result of wind speed, the most attractive regions in Turkey for wind energy applications are the Marmara (northwest side of Turkey) which is followed by the southeast Anatolian and the Aegean regions (west side of Turkey) [19].

Solar, wind, geothermal and hydro energy potential fields in Turkey are shown in Fig. 3. In the case of the west of Turkey, wind energy can be considered as the best energy resource for heating or electricity. Moreover, if the area is in the southeast Anatolia or the Mediterranean regions, energy can be supplied with solar energy, utilizing photovoltaic systems or solar collectors [20].

As is seen Figs 2 and 3, the coasts of the Mediterranean, Aegean and Marmara Seas have high wind energy potential while the south side of Turkey, including some coasts of the Mediterranean and Aegean Seas, has high solar energy potential.

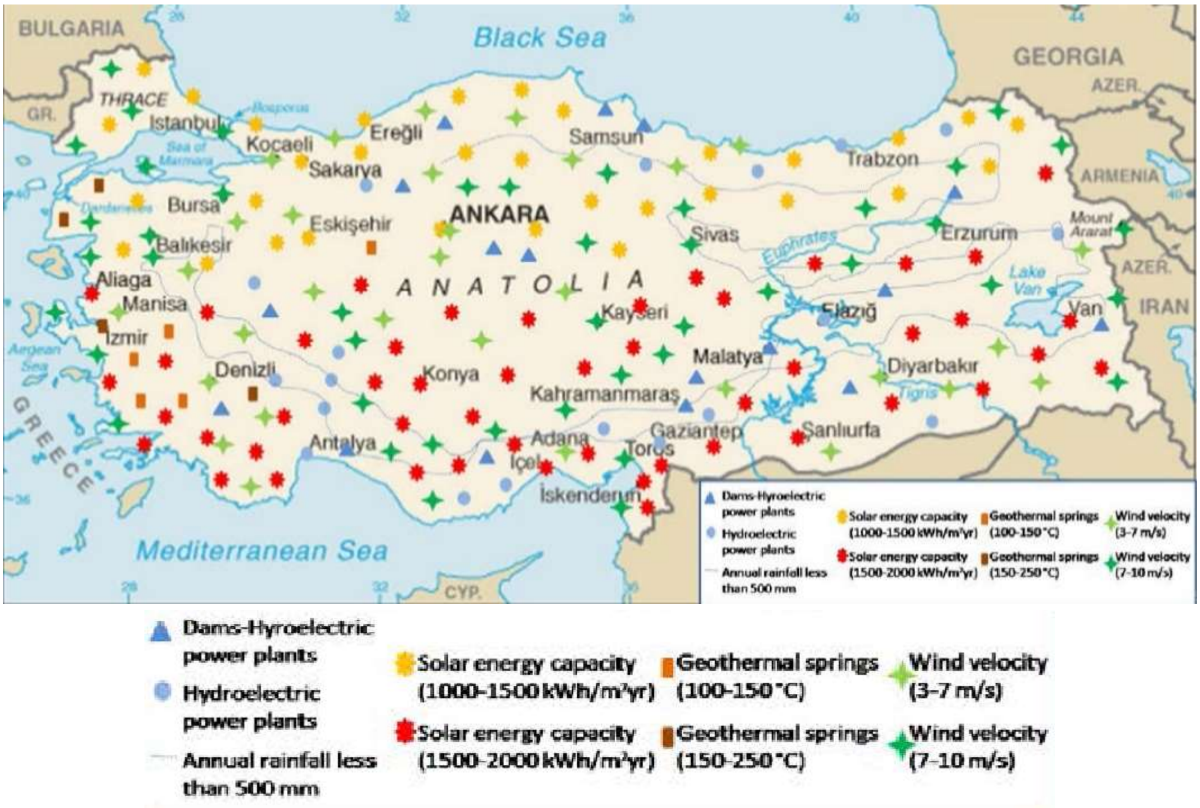

FIG. 3. Solar, wind, geothermal and hydro energy potential fields in Turkey [20].

There are three models in the renewable energy market of Turkey as the unlicensed, licensed and renewable energy resource zone (YEKA/RE-Zone). In the unlicensed model, renewable energy systems producing up to 1 MW of energy do not need a license and are eligible for the specific renewable energy support tariffs for the first ten years of operation. In the licensed model, renewable energy systems produce more than 1 MW of energy. Most of the power plants in Turkey are constructed with this licensed model. In the RE-Zone model, renewable energy zones in Turkey are determined by the government and renewable energy investments can be done more rapidly to use locally manufactured equipment/components and to contribute to research and development activities through technology transfer. The installed capacity and generation development of renewables in Turkey are given in Table 2 [17].

TABLE 2. INSTALLED CAPACITY AND GENERATION DEVELOPMENT OF RENEWABLES IN TURKEY

SOURCE	NUMBER OF PLANTS IN 2017	INSTALLED CAPACITY IN 2017 (MW)	INSTALLED CAPACITY IN 2019 (MW)	INSTALLED CAPACITY IN 2023 (MW)
Biomass	98	575	700	1000
Solar	3619	3421	3000	10 000
Geothermal	40	1064	700	1500
Wind	161	6516	10 000	20 000
Hydraulic	618	27 273	32 000	34 000

2.2. Nuclear energy in Turkey

Turkey has attempted to construct nuclear power plants since the 1970s; however, construction did not start until 2018. Today, there are three projects under construction, planned and proposed for nuclear power plants in Turkey. Fig. 4 shows the under construction, planned and proposed nuclear power plants locations in Turkey. One of them, Akkuyu nuclear power plant in Mersin city (southern area of Turkey) on the Mediterranean Sea side, has been under construction since April 2018 and is planned to start producing power between 2021 and 2024 [21]. The other (planned) one is Sinop nuclear power plant in the Sinop city (northern area of Turkey) on the Black Sea side. Its construction will start in 2019 and will start producing power between 2023 and 2028. The last (proposed) one is Igneada nuclear power plant in Kırklareli city (northern area of Turkey) on the Black Sea side. Igneada nuclear power plant project is a newly proposed one and will be built after the Sinop nuclear power plant, that will be constructed after the Akkuyu nuclear power plant. Igneada nuclear power plant will be located in the European side of Turkey, while the others (Akkuyu and Sinop) are in the Asian side. In addition to those nuclear power plants, the Turkish government has announced intentions for two additional nuclear power plants with four reactors each, all to be operational by 2030. The under construction, planned and proposed nuclear power reactors of Turkey are listed in Table 3 [9,21].

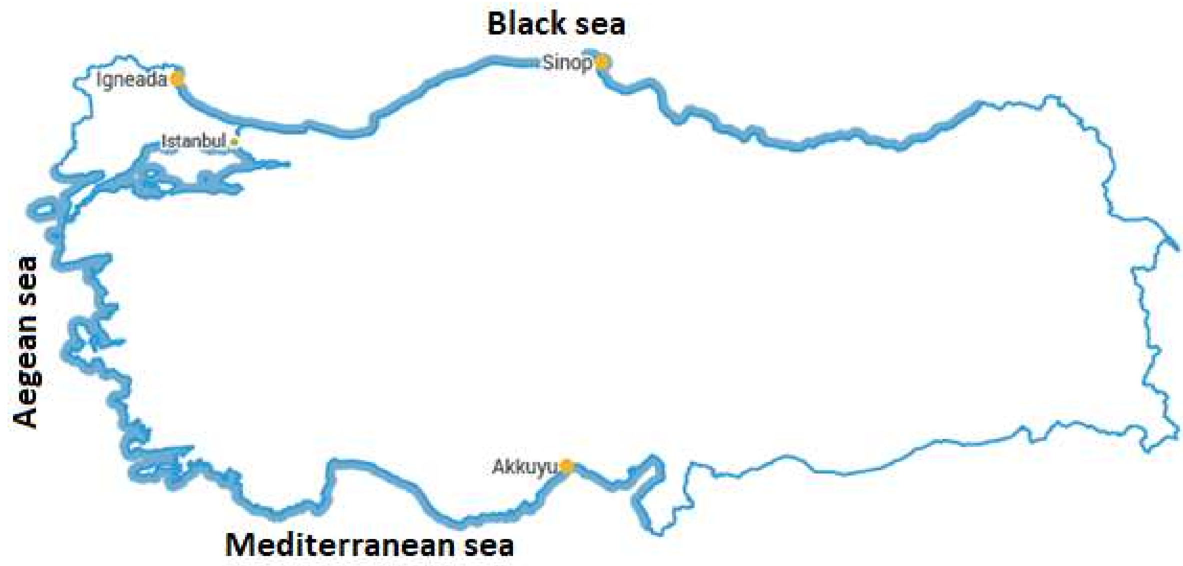

FIG. 4. Under construction, planned and proposed nuclear power plants locations in Turkey (adapted from [21]).

The total capacities of the Akkuyu, Sinop and Igneada nuclear power plants are 4800 MW_e, 4600 MW_e, 5300 MW_e, respectively. Akkuyu nuclear power plant will use four VVER-1200 type reactors which are known as the water–water energetic reactors (WWER/VVER) (pressurized water reactor series). VVER-1200 reactor has 1200 MW_e capacity and has been used in European, Asian and Middle Eastern countries since the 1970s. There are various types of VVER reactors (70, 210, 365, 440, 1000 and 1200 models) and the VVER-1200 model is the most modern one that started commercial operation, in 2017 [22]. Sinop nuclear power plant will be operated by four Atmea1 type, each 1150 MW_e capacity, nuclear reactors which are new Generation III+ and medium power pressurized water reactors developed in 2007 [23]. Igneada nuclear power plant will use two AP1000 and two CAP1400 types of nuclear reactors. The AP1000 reactor is a modern pressurized water reactor with improved use of passive nuclear safety. The first AP1000 began operation in 2018 and its capacity is 1250 MW_e [24]. On the other hand, CAP1400 is an enlarged version of the AP1000 pressurized water reactor with 1400 MW_e capacity [25].

2.3. Climate change and global warming effects of Turkey

Turkey is the 20th largest greenhouse gas (GHG) emitter in the world and it is one of the countries which is most affected by global warming, as its annual temperatures are rising every year [26]. Turkey emits 1% of global greenhouse gases, and the emissions are forecast to rise substantially. The greenhouse gas inventory results revealed that the overall GHG emissions as CO_2 equivalent for the year 2016 were 496.1 million tonnes. The energy sector accounted for the largest share of GHG emissions at 72.8% and was followed by industrial processes and product use with 12.6%, agricultural activities with 11.4% and waste with 3.3%. CO_2eq. emissions per capita was calculated as 6.3 tonnes and emission intensity was calculated as 0.19 kg CO_2eq./GDP (TL) for the year 2016 [27]. The predicted GHG emissions per capita of some countries in 2030 are illustrated in Fig. 5. Turkey's GHG emission per capita will reach to 10.51 tCO_2eq., while the world's rate is 6.5 tCO_2eq. [28].

Fig. 6 shows the level of carbon dioxide emissions in Turkey from 2000 to 2017. Emission levels increased during the period, rising from 206.4 million metric tons of carbon dioxide emitted in 2000 to 410.9 million metric tons of carbon dioxide emitted in 2017 [29].

The Turkish electrical energy 5 year generation capacity projection of TEIAS [30] is used to estimate the GHG emissions by electricity generation according to source type. The greenhouse gas emissions by electricity generation of Turkey is given in Table 4 [31].

Fossil fuels, especially natural gas and lignite, have the highest GHG effects, while renewable energies have the minimum rate. Currently, there is no nuclear power plant to produce electricity, so its GHG rate is considered as zero.

TABLE 3. UNDER CONSTRUCTION, PLANNED AND PROPOSED NUCLEAR POWER REACTORS OF TURKEY

PLANT NAME	TYPE	MW_e GROSS	START CONSTRUCTION	START OPERATION
Akkuyu 1	VVER-1200	1200	April 2018	2023
Akkuyu 2	VVER-1200	1200	2019	2023
Akkuyu 3	VVER-1200	1200	2020	2024
Akkuyu 4	VVER-1200	1200	2021	2025
Sinop 1	Atmea1	1150	—	2024/2025
Sinop 2	Atmea1	1150	—	2025/2026
Sinop 3	Atmea1	1150	—	—
Sinop 4	Atmea1	1150	—	—
Igneada 1–4	AP1000x2 CAP1400x2	2x1250 2x1400	—	—

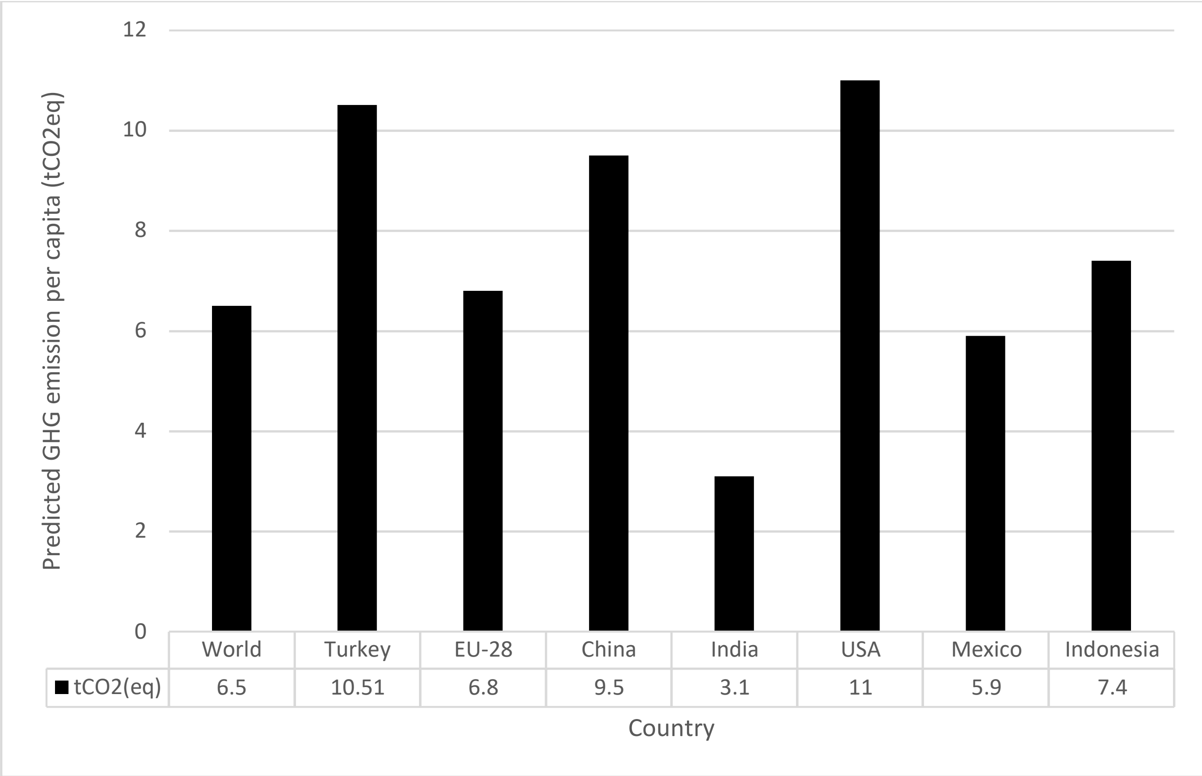

FIG 5. Predicted GHG emission per capita of some countries in 2030 (adapted from [28]).

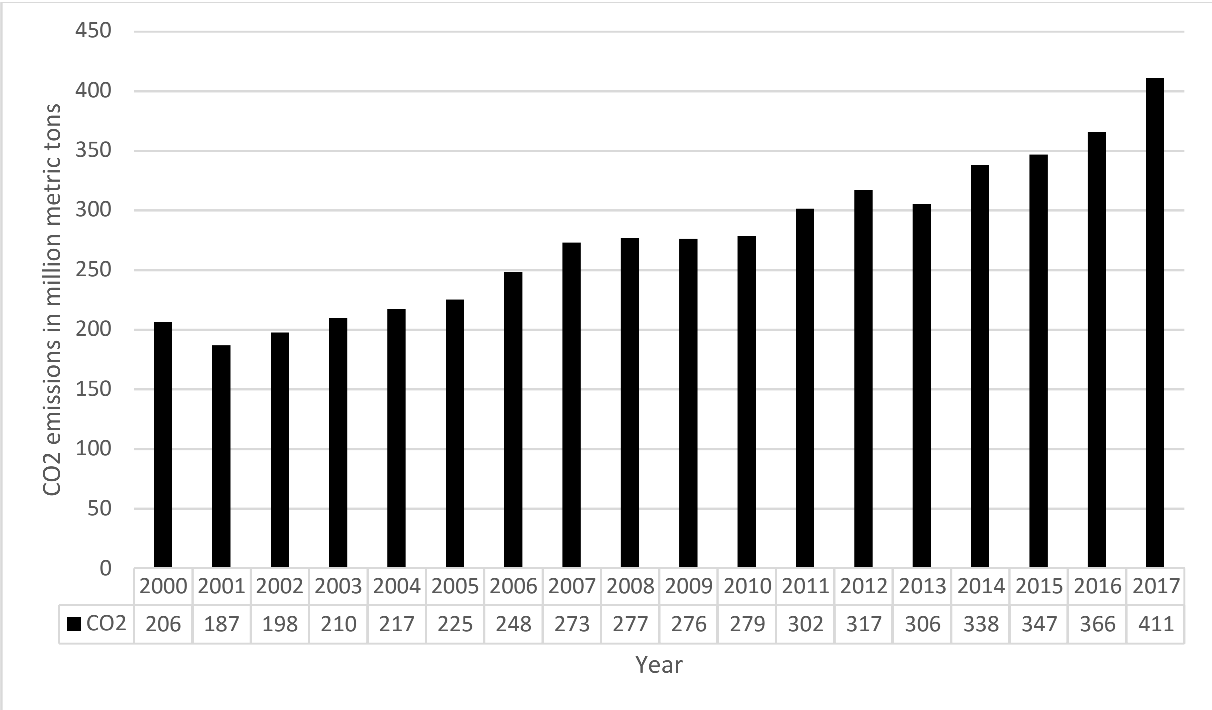

FIG. 6. Carbon dioxide emissions in Turkey from 2000 to 2017 (adapted from [29]).

TABLE 4. GREENHOUSE GAS EMISSIONS BY ELECTRICITY GENERATION OF TURKEY

SOURCE	GREENHOUSE GAS EMISSION (MILLION TONS CO_2 EQUIVALENT)				
	2013	2014	2015	2016	2017
Natural gas	84.706	85.307	89.354	89.88	89.88
Lignite	46.501	46.878	53.254	56.21	56.21
Hard coal	2.480	2.480	2.480	4.34	4.34
Imported coal	2.261	2.261	8.318	8.32	15.88
Petroleum products	8.708	8.708	10.177	10.77	10.77
Nuclear	0.000	0.000	0.000	0.00	0.00
Hydroelectric	1.212	1.278	1.462	1.52	1.52
Wind	0.067	0.074	0.086	0.09	0.09
Geothermal	0.049	0.072	0.088	0.09	0.09
Biomass	0.034	0.037	0.040	0.04	0.04
Solar PV	0.000	0.000	0.000	0.00	0.00
Total	146.019	147.096	165.258	171.257	178.823

3. PROPOSED HYBRID NUCLEAR–RENEWABLE ENERGY SYSTEMS FOR TURKEY

Nuclear power is the best option as an alternative to renewables for reducing carbon emissions in the electricity sector. The combination of renewables with nuclear energy can provide a large fraction of a system's electricity, while minimizing inefficiencies associated with curtailed generation or energy storage losses. This hybrid combination also decarbonizes the electricity sector [4]. The advantages of hybrid nuclear–renewable energy systems are as follows [2,32]: (a) reduction of greenhouse gases, (b) mitigation of climate change and global warming, (c) creating a competitive area for renewable energy, (d) enhancing green energy utilization for generations, (e) increasing energy conversion efficiency by using smart control and heat management technologies, (f) reliable, economical and continuous electricity production, (g) capability of producing biofuel or hydrogen, (h) reducing the fossil fuel transportation dependence, and (i) helping decarbonization.

Turkey is one of the energy importing countries, so it is necessary to use sustainable sources so as to be less dependent on other countries. In this regard, hybridization of renewable and nuclear combination is a sustainable, economical and environmentally friendly alternative for Turkey. Turkey has numerous advantages for extensive use of most of the renewable energy sources (such as solar, biomass, wind, hydropower, geothermal) due to its warm climate like most of Europe, the near east and western Asia. Therefore, it is very effective to use renewable energies to combine with nuclear energy in Turkey [33].

There are various possible hybrid nuclear renewable energy options that may be effectively used in Turkey for sustainability and climate change mitigation. Considering the renewable energy potential of Turkey, as explained above, the hybridization of nuclear energy with solar and wind renewable energies are investigated.

One hybrid system is a hybrid nuclear–solar tower energy system, such as that proposed by Popov and Borissova [34], consisting of a pressurized water reactor, hot and cold thermal energy storage tanks, solar tower receiver, heliostats, turbine–generator system, superheater and reheater, water pumps and condenser. The schematic layout of the proposed hybrid nuclear–solar tower energy system is illustrated in Fig. 7. This figure shows the single module structure for simplicity; however, it can be enhanced as multimodule for higher capacity.

The proposed nuclear–solar tower hybrid energy system generates thermal power by using solar radiation on the solar tower receiver that includes tube panels through which molten salt flows. Thermal energy storage (TES) tanks store liquid salts and use a 40% KNO_3 + 60% $NaNO_3$ mixture as a storage medium. The process starts with the rising of the sun as cold liquid salt flows from the cold tank through the tubes inside the solar tower receiver. The heliostats reflect sunlight toward the solar tower receiver. The temperature of the molten salt is increased by absorbing solar energy in the solar tower receiver and some is pumped for storing in the hot thermal energy storage tank, while some of the molten salt is sent to the superheater and reheater (shell and tube type) heat exchangers for achieving equality in high pressure and reheat steam temperatures. Molten salt is then stored into the cold thermal energy storage tank. This cycle can be used over and over, and excess heat can be stored for power generation when solar radiation is not enough or when the sky is cloudy. This proposed hybrid nuclear–solar tower energy system can act as a steam generator. The amount of heat produced by a nuclear reactor, temperature and pressure are kept constant. The return water temperature is also kept constant. Hence, the reactor's inlet and outlet parameters are kept at nominal design levels. Hot molten salt is used to superheat the nuclear steam, then, nuclear steam enters the turbine's high pressure side. After that, nuclear steam is reheated by hot molten salt before going to the turbine's intermediate pressure side (after the high pressure side). Hence, moisture is eliminated at the exit of the turbine and spent steam is sent to the condenser. The turbine is connected with generator unit, so the turbine–generator unit produces electricity for the utility grid. Extracted steam of the steam turbine is used for preheating feedwater. This hybrid system has a mechanical draft, wet cooling tower where heat is rejected via evaporation and convection and cooled water returns to the condenser [34].

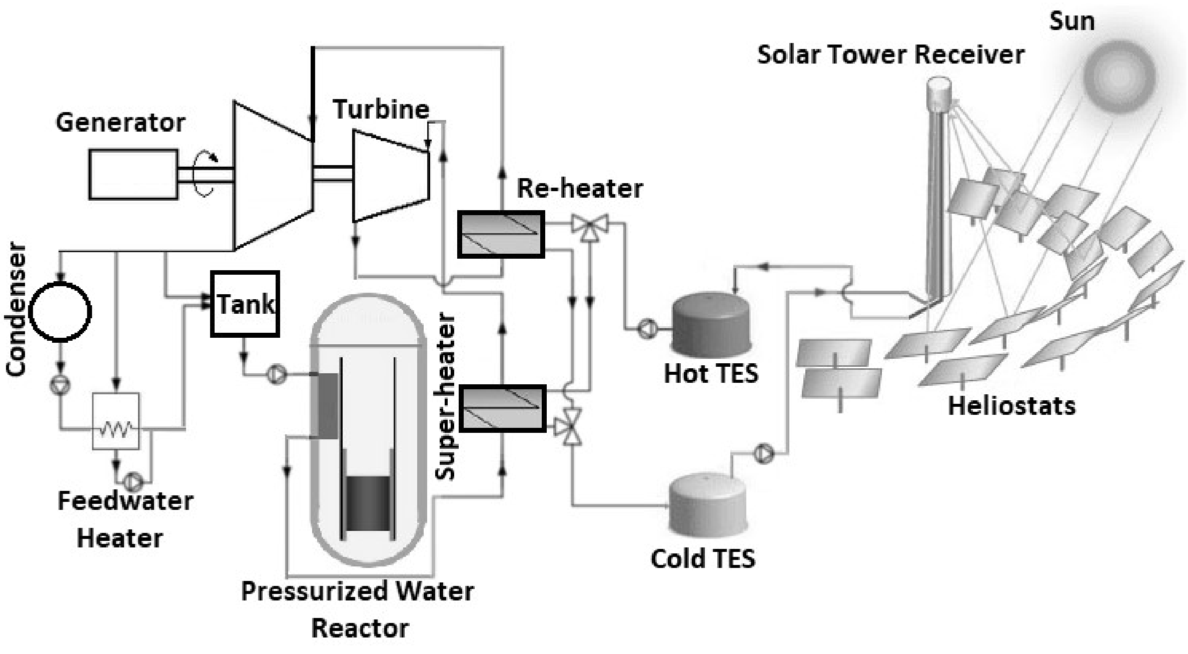

FIG. 7. Proposed hybrid nuclear–solar tower energy system for Turkey (adapted from [34,35]).

The other proposed hybrid nuclear–renewable energy system (hybrid nuclear–solar parabolic through collector energy system) is shown in Fig. 8 and consists of solar parabolic through collector unit, pressurized water reactor, hot and cold thermal energy storage tanks, turbine–generator system, superheater, reheater, water pumps and condenser [36]. This hybrid nuclear–solar parabolic through collector energy system is almost similar to nuclear–solar tower energy system as explained above. The only difference is utilization of solar parabolic through collector unit instead of solar tower receiver and heliostats. Also, there is a heat exchanger for thermal energy storage (TES) systems. In this process, cold liquid salt flows from the cold tank to the solar parabolic through collector unit and its temperature rises. After that, some of the molten salt is pumped for storing in the hot thermal energy storage tank, while some is sent to the superheater and reheater. The rest of the process is similar to the hybrid nuclear–solar tower system as explained before.

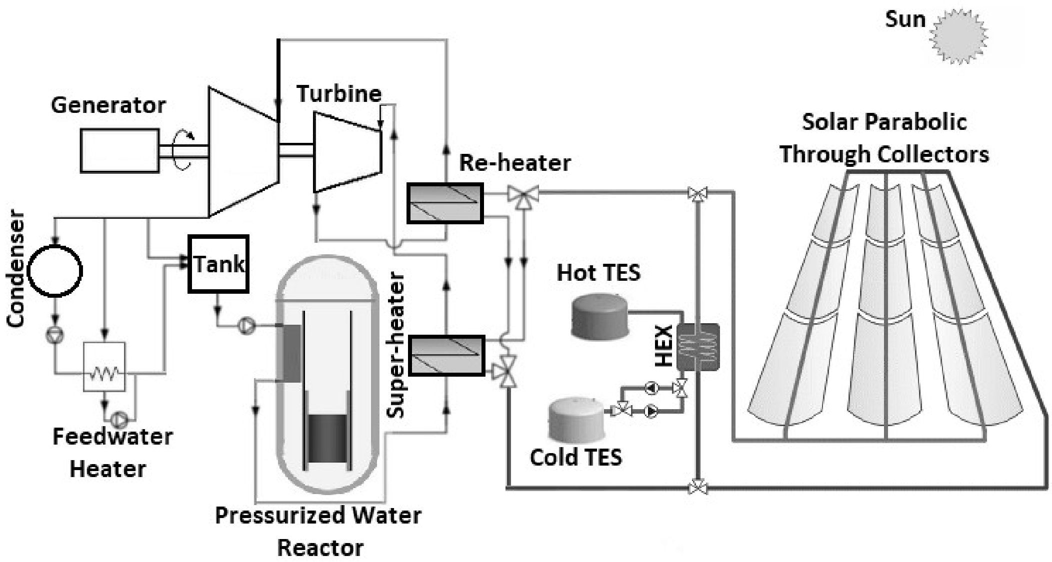

FIG. 8. Proposed hybrid nuclear–solar parabolic through collector energy system for Turkey (adapted from [36]).

In both of the proposed hybrid nuclear–solar energy systems, the solar heat is transferred to nuclear steam to increase its temperature. Continuous superheating is provided through thermal energy storage. As a result, solar superheating has the potential to increase nuclear plant electric efficiency significantly [2,34,36].

Another hybrid system is a nuclear–wind energy system that includes a light water small modular nuclear reactor, wind power plant, thermal power cycle that converts nuclear generated thermal energy to electricity, electric boiler and thermal storage unit. Fig. 9 shows the proposed hybrid nuclear–wind energy system. Considering Turkey's wind energy speed and fields, this hybrid system can be used in Turkey effectively. In this system, an electrical boiler is used to convert grid electricity and produced electricity of wind turbines to thermal energy. A molten salt thermal storage unit is also included. The thermal storage unit used in this system can store thermal energy from either electric boiler or nuclear reactor. In this process, the thermal product is constant. The options of this hybrid system can be expressed as follows: (a) nuclear reactor generates only thermal energy, (b) nuclear reactor and thermal power cycle (plant) generate electricity, possibly in conjunction with thermal energy, (c) wind power plant generates only electricity, (d) wind power plant and electric thermal storage device generate thermal energy, possibly in conjunction with electricity sold to the grid, (e) nuclear reactor and wind power plant generates only thermal energy and electricity, respectively, (f) nuclear reactor and thermal power cycle (plant) generate electricity, possibly in conjunction with thermal energy, and the wind power plant generates electricity, (g) nuclear reactor generates only thermal energy and the wind power plant and electric thermal storage device generates thermal energy, possibly in conjunction with electricity sold to the grid (h) nuclear reactor and thermal power cycle (plant) generate electricity, possibly in conjunction with thermal energy, and the wind power plant and electric thermal storage unit generate thermal energy, possibly in conjunction with electricity sold to the grid [37].

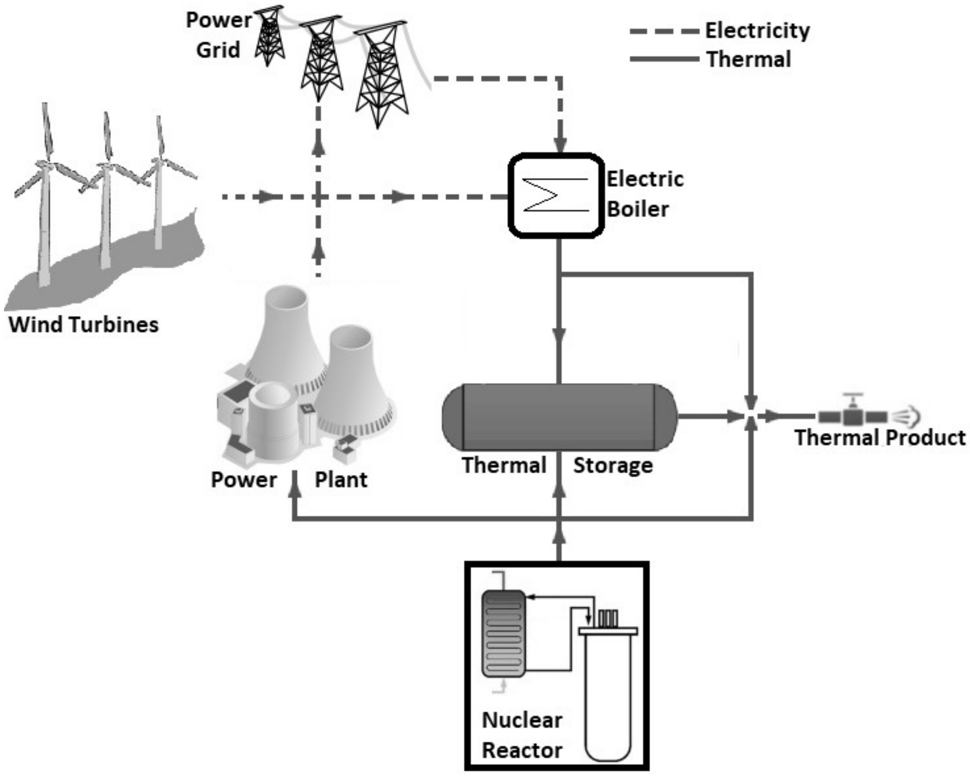

FIG. 9. Proposed hybrid nuclear–wind energy system for Turkey (adapted from [37]).

4. CONCLUSION

Hybrid nuclear–renewable energy systems are combined systems of renewable energy and nuclear reactors to reach better sustainability, reduced greenhouse gas emissions and grid flexibility. In this study, Turkey's greenhouse gas information, renewable energy sources/fields/installations and planned nuclear power plants are investigated. Also, the possible hybridization of nuclear and renewable energies considering solar and wind renewable energy fields and potentials are studied. Turkey has a high wind and solar energy potential due to its geographical location as Eurasia. There are already installed wind and solar renewable energy systems for clean and sustainable electricity production in Turkey. However, the necessity of electricity in Turkey is high and most of them are supplied by imported energy sources. Therefore, new solutions for sustainable, clean and secure electricity production are necessary. Three sides of Turkey have seas, effective for construction of nuclear power plants. Turkey is planning to build five nuclear power plants with three of them are announced, while one started construction in April 2018. Considering the advantages of hybrid nuclear–renewable energy systems, the combination of nuclear energy with solar and wind renewable energies are investigated. The hybrid nuclear–solar tower collector energy system, hybrid nuclear–solar parabolic through collector energy system and hybrid nuclear–wind energy system are taken into account and proposed for possible installation in Turkey. It is seen that all of these three options can be effectively constructed in Turkey due to high solar and wind potentials. The best hybrid nuclear–wind energy system locations can be the Mediterranean Sea and/or Marmara Sea coasts of Turkey, while the best hybrid nuclear–solar energy system locations are the Aegean Sea coast and/or the Mediterranean Sea coasts of Turkey for sustainable and environmentally friendly power production.

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U.S. RESEARCH & DEVELOPMENT STATUS FOR INTEGRATED NUCLEAR-RENEWABLE ENERGY SYSTEMS

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Abstract

The U.S. Department of Energy (DOE) Office of Nuclear Energy (NE) program on Nuclear-Renewable Hybrid Energy Systems (N-R HES) was established to evaluate potential options for the coordinated use of nuclear and renewable energy generators to meet energy demands across the electricity, industrial, and transportation sectors. Implementation of novel systems integration and process design will allow for expanded use of nuclear energy beyond the grid, complementing the increasing penetration of variable renewable energy generation that is requiring more flexibility from other generators on the grid. This complementary use of generation technologies is accomplished through provision of energy services and production of saleable commodities (e.g. potable water, hydrogen, etc.) produced using excess thermal and electrical energy from the nuclear system. Increased flexibility and applicability of traditionally baseload nuclear systems will support domestic energy security, grid reliability and grid resilience while maximizing the use of clean energy technologies. This paper provides an overview of the current N-R HES program scope for system design and optimization and experimental demonstration.

1. INTRODUCTION

A sustainable, balanced energy portfolio that provides reliable, resilient electricity at stable, affordable prices is necessary for continued U.S. prosperity. A primary goal of the U.S. DOE is to ensure U.S.

competitiveness by domestically producing energy products and services using the best mix of available natural resources. There is an expectation that system wide integration or enhanced coordination of the U.S. energy sectors can reduce the overall cost of energy by providing increased operational flexibility, increased efficiency, and higher utilization of power generation assets.

Rapid buildout of renewable technologies has been largely driven by local, state, and federal policies, such as renewable portfolio standards and production tax credits that incentivize investment in these generation sources. A foundational assumption within the N-R HES program is that renewable technologies will continue to be major contributors to the future U.S. energy infrastructure. While increased use of clean renewable technologies will aid in achieving reduced emissions from electricity generators, it also presents new challenges to grid management that must be addressed. These challenges primarily derive from the fundamental characteristics of variable renewable generators, such as wind and solar: non-dispatchability, variable production, and reduced electromechanical inertia.

As the fraction of variable renewable generators contributing to grid electricity production increases, many regions in the U.S. are seeing periods of overproduction that results in temporary low or even negative electricity pricing, causing baseload electricity suppliers, such as nuclear and coal, to either reduce generation in real time (sometimes referred to as 'flexible' operation or 'advanced economic dispatch') or to sell electricity at a loss [1,2]. Either of these options drives down the overall plant economic performance. This scenario, coupled with the current low cost of natural gas in the U.S., has resulted in premature closure of several baseload nuclear plants (prior to license expiration), with additional closures predicted [3,4]. A proposed solution is to repurpose traditionally 'baseload' nuclear plants for use in integrated energy systems that leverage the thermal and electrical contributions from multiple generators to meet a range of energy needs, combined with enhanced coordination of those energy systems across the broader grid balancing areas. The overview presented in this paper focuses on the use of nuclear fission energy systems, in coordination with variable renewable generators (e.g. solar photovoltaic (PV) and wind), within 'hybrid' energy systems designed and controlled in a manner that maximizes flexibility and economic performance while ensuring grid reliability and resilience. A vision for a possible suite of options within 'hybrid energy systems' is depicted in Fig. 1.

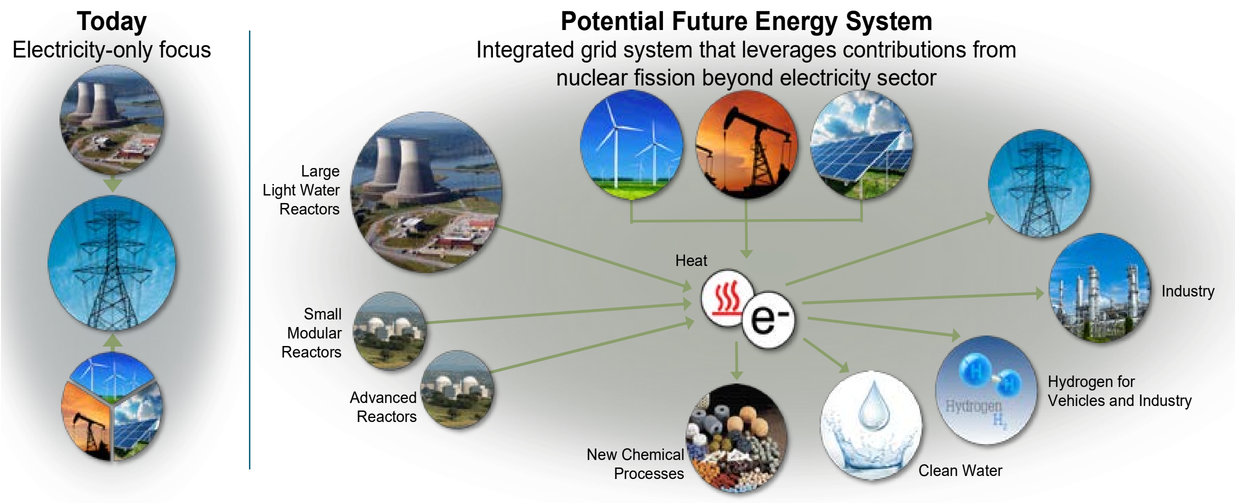

FIG. 1. Coordination of energy generation sources and demand to maximize flexibility and economic performance while ensuring grid reliability and resilience [5].

Each of the major energy sectors — the electric grid, industrial manufacturing, transportation, and residential/commercial consumers — is increasingly becoming linked through information and communications technologies, advanced modelling and simulation, and controls. Integration and/or coordination of clean energy generation technologies has the potential to revolutionize energy services at the system level by coordinating the exchange of energy currency among the energy sectors in a manner that optimizes financial efficiency (including capital investments), maximizes thermodynamic efficiency (through best use of exergy, which is the potential to use the available energy in producing energy services), reduces environmental impacts when clean energy inputs are maximized, and provides resources for grid management.

This paper provides an overview of the nuclear-renewable hybrid energy systems (N-R HES) program, which is funded via the U.S. Department of Energy Office of Nuclear Energy (DOE-NE) under the Crosscutting Technologies Program area. N-R HES are cooperatively controlled systems that dynamically apportion thermal and/or electrical energy to provide responsive generation to the power grid. They are comprised of multiple subsystems, which may or may not be geographically collocated:

— A nuclear heat generation source;
— A turbine that converts thermal energy to electricity;
— At least one renewable energy source;
— An industrial process that utilizes heat and/or power from the energy sources to produce a commodity scale product (e.g. potable water, hydrogen, ammonia, steel, etc.).

Subsystems that are a part of an integrated system may be collocated and tightly coupled, or they could be geographically dispersed depending on the technologies selected for energy use. Note that the fraction of renewable penetration within the system boundary and relative sizes of each subsystem are parameters in the optimization process described below (see Modelling & Simulation for System Design and Optimization).

The N-R HES work is closely coordinated with the Hydrogen at Scale (H2@Scale) program, illustrated conceptually in Fig. 2, which is funded via the U.S. DOE Office of Energy Efficiency and Renewable Energy (DOE-EERE) Fuel Cell Technologies Office (FCTO). H2@Scale explores the potential for wide scale hydrogen production and use in the U.S. to enable resilience of the power generation and transmission sectors, while also aligning diverse, multi-billion dollar domestic industries, domestic competitiveness, job creation, and global imperatives. While hydrogen generation is an initial focus of system design and analysis case studies for the N-R HES program, it is just one of many possible energy users that could be supported by an N-R HES.

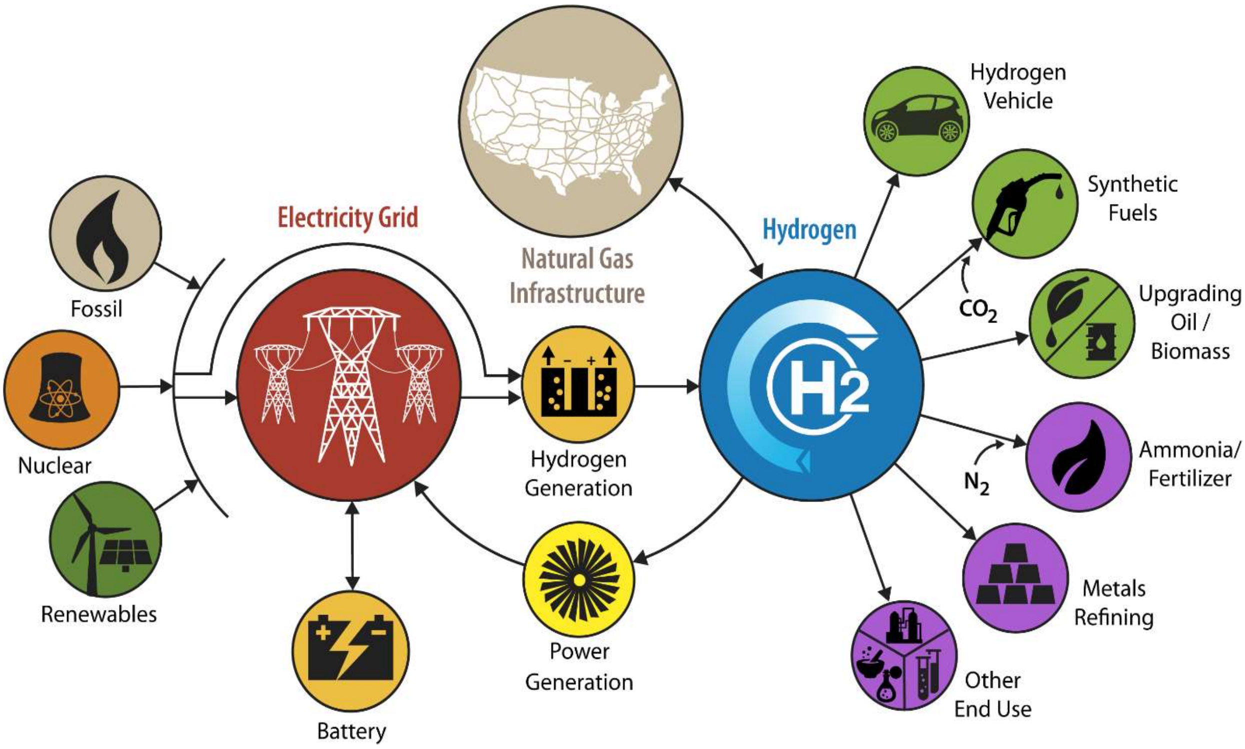

FIG. 2. Summary Depiction of the Hydrogen at Scale Program (image courtesy of NREL).

A concerted effort to define the constituent technology development needs for N-R HES is essential. A technology development program plan issued in March 2016 outlines significant analysis efforts, including high fidelity, dynamic modelling and simulation, which will guide the definition of hardware development and demonstration efforts necessary to advance N-R HES to deployment [6]. Research and development activities are defined within two major areas:

— **Modelling and Simulation**: Tool development and associated analysis to assess technical and economic viability and to determine optimal system design and energy dispatch.
— **Experimental Demonstration**: Electrically heated system testing to demonstrate hardware interfaces, control systems, dynamic operation, etc.

The current high level status of work in each of these areas is summarized in the following sections.

2. MODELING & SIMULATION FOR SYSTEM DESIGN AND OPERATIONAL OPTIMIZATION

The N-R HES program is currently investigating technical and economic viability for a range of possible configuration options for several regions of interest, with a specific focus on selected case studies that consider retrofit or repurposing of existing fleet light water reactors (LWRs). Detailed dynamic analysis is necessary to optimize the N-R HES design configurations that are the most promising for near term applications, and which may lead to the deployment of a variety of system options in the future. The relevance of N-R HES buildout in future energy markets is expected to be significant given the anticipated benefits of dispatchability, flexibility, real inertia for the grid, reduced carbon emissions beyond the electric generating sector, and stabilized energy costs. The technical, environmental, and economic evaluations performed for N-R HES concepts will be compared to alternative future energy infrastructures that could be capable of meeting the defined environmental, sustainability, and economic goals while maintaining grid resilience.

The overarching goal of the modelling and simulation activity is to optimize economic performance of candidate integrated energy system options under technical performance constraints and assurance of grid resilience. There are four main cornerstones of the simulation framework: generation of stochastic time series, a probabilistic analysis and optimization set of algorithms implemented in the INL developed Reactor Analysis and Virtual Control ENvironment (RAVEN) tool, models that represent the physical behaviour of N-R HES developed using the Modelica language, and a RAVEN module developed specifically for the N-R HES program that maps physical performance into economic performance. The analysis approach applies a two layer optimization in which the nominal capacities of integrated system components are optimized for a particular implementation (geographic location, characterized by historical grid demand and renewable generation) within technical constraints for each component or subsystem (e.g. up/down ramping rates, minimum/maximum capacities, etc.) to achieve the minimum cost of electricity for the system over a simulated 1 year period. For the selected system design, the real time dispatch of energy within the system, e.g. to electricity generation or to support the production of a non-electric commodity, is determined using simulated time histories for renewable generation, grid net demand, and detailed dynamic models for the included subsystems.

Fig. 3 provides a simplified graphical representation of the multilayer optimization approach, and Fig. 4 provides sample output from an optimization problem in a five-dimensional plot of the net demand (total demand less the renewable generation), industrial process (IP) capacity, gas turbine capacity, energy storage (ES) capacity, and levelized cost of electricity (LCoE). This generalized case assumes a fixed reactor capacity of 300 MW_e installed in a region with wind capacity that is twice the mean demand. The minimum LCoE was determined using both detailed component models that represent the dynamic performance of the integrated components and the overarching RAVEN tool. Additional detail on this analysis and optimization process is provided in references [7–9].

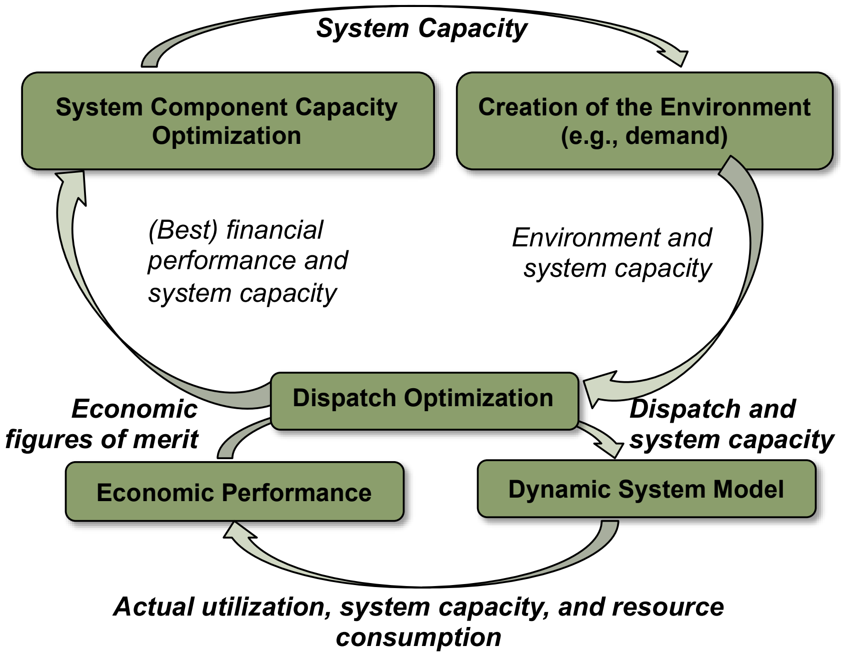

FIG. 3. Optimization approach applied for integrated system design and operational dispatch optimization; dynamic system models are developed in Modelica, while the optimization and economic performance calculations are accomplished using the tools developed in RAVEN.

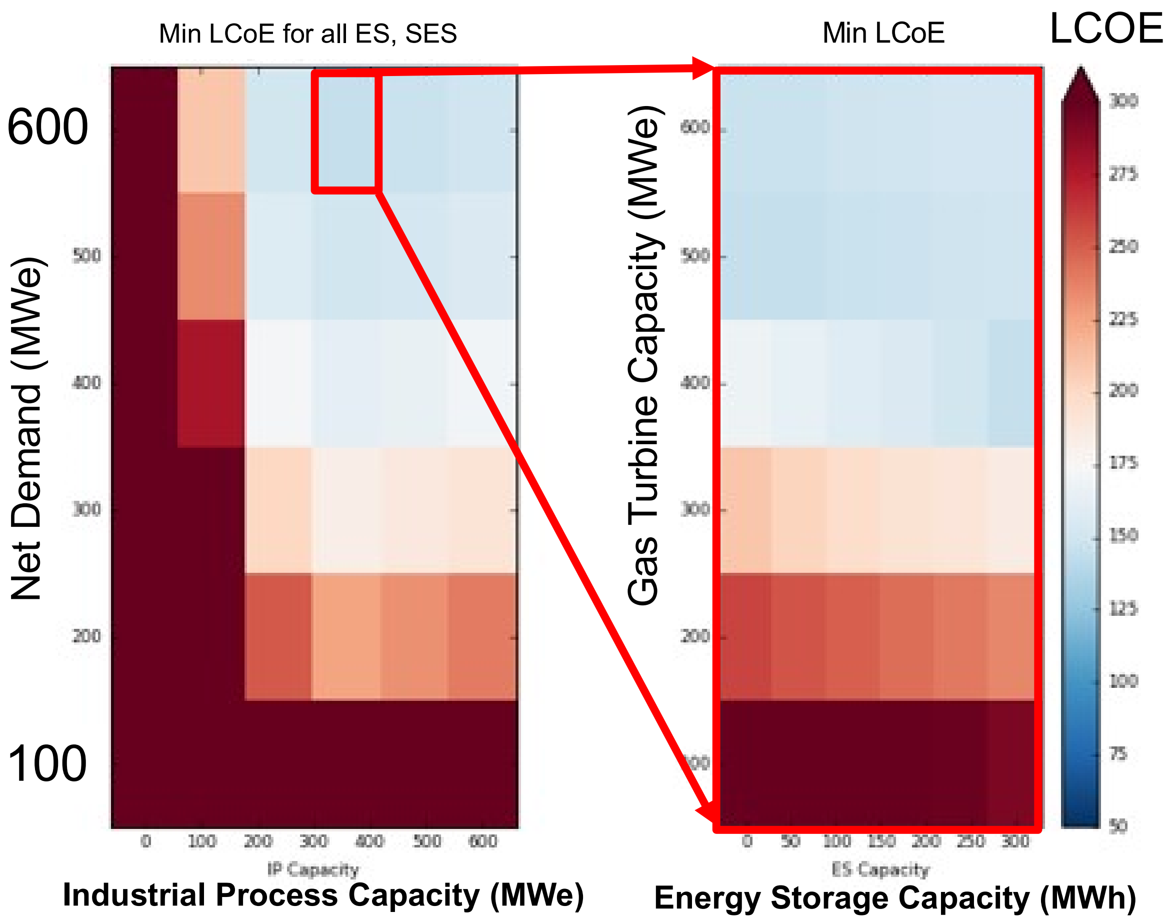

FIG. 4. Example interim output from component sizing optimization; example corresponds to a fixed reactor size of 300 MW_e and installed wind capacity equivalent to twice the mean demand.

Fig. 5 illustrates the dispatch of energy from the nuclear plant for the example case run to show tool functionality. As noted above, this example case assumes a 300 MW_e reactor, wind generating capacity of twice the mean demand, and installation of an electric battery and a gas turbine to allow demand to be met when output from the nuclear plant is used for the production of a non-electric commodity (e.g., hydrogen in this example). The component sizes are optimized to provide the minimum LCOE over a 1 year period using real data for demand, electricity pricing, and wind generation in a selected region to train synthetic time histories applied in the optimization; economic evaluation includes capital costs to install all subsystems and the associated operations and maintenance costs over the lifetime of the plant. The dispatch optimization applies penalties for both under and over generation, and it assumes a minimum fraction of energy sent to the IP (e.g. H_2 plant) at all times; note that the energy to the industrial process is shown as negative capacity dispatched (brown) because it is not used to meet grid net demand. The remainder of the nuclear generated energy is dispatched to the nuclear system balance of plant (shown in blue) to produce electricity. Charging and discharging of the electrical battery are shown in green, whereas the times during which the gas turbine is used are shown in red. One may note that the peak demand is not always met. This example assumes that other generators are available in the grid balancing area to meet peak demand; the optimization algorithm determined that it is not economically beneficial to install a higher capacity gas turbine or electric battery to meet these short duration periods of higher demand.

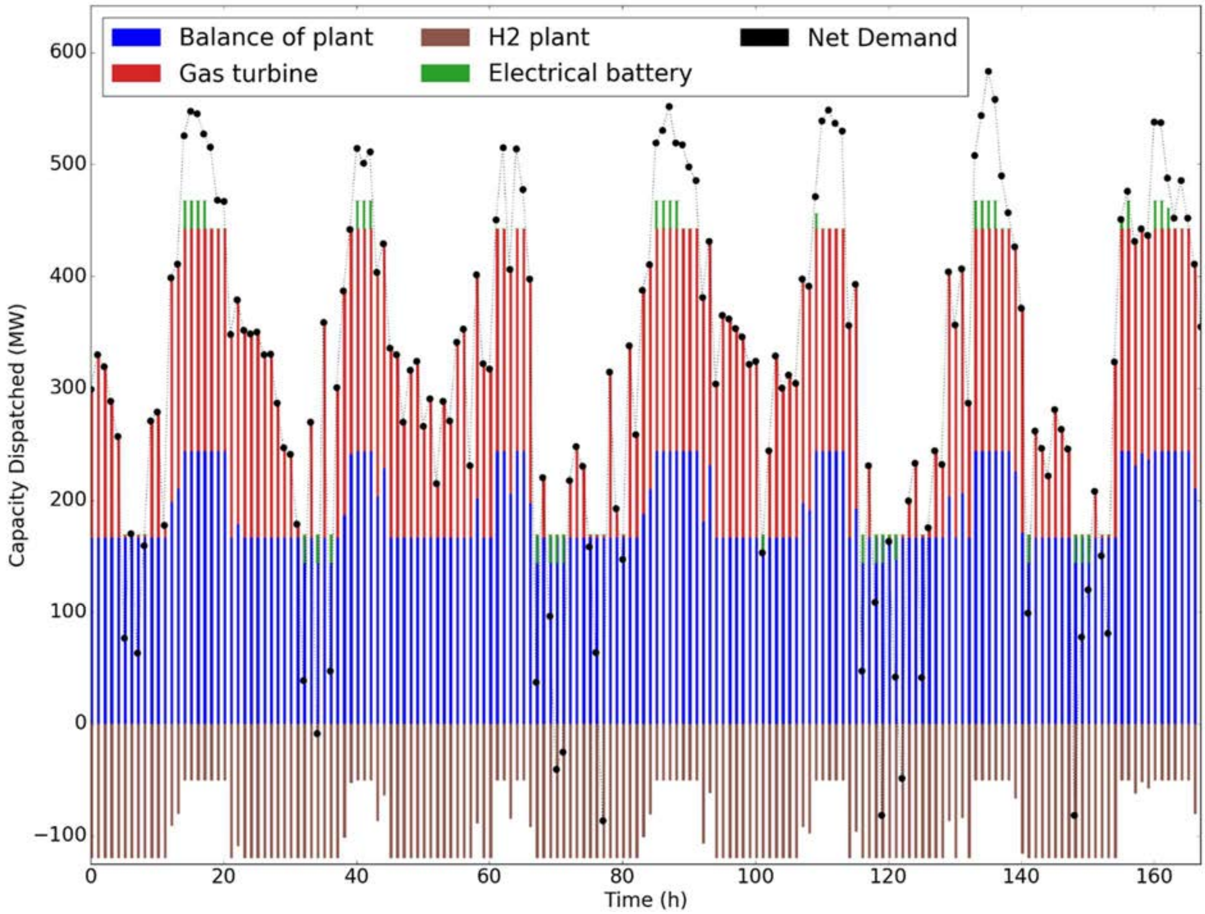

FIG. 5. Example energy dispatch for a system optimized using time histories for wind generation and grid demand over a one-year period. Results shown correspond to a single time history for a one-week operational period.

In partnership with operating nuclear utilities in the U.S., this simulation framework is currently being applied to evaluate the technical and economic performance of N-R HES for selected plants in the current LWR fleet. Specific cases focus on (1) a region with high solar photovoltaic penetration and a desire to produce potable water from regional brackish groundwater for plant cooling [9], and possibly for use within surrounding municipalities, and (2) a region having high wind penetration and possible growing markets for hydrogen that could be produced by excess thermal and electrical energy from a nuclear plant.

3. EXPERIMENTAL DEMONSTRATION OF INTEGRATED SYSTEMS

As discussed above, high fidelity, dynamic modelling and simulation tools have been developed and are being further refined to optimize system design and operation. The research team is now moving toward concept demonstration, first in a scaled, electrically heated integrated test facility at INL and later followed by demonstration on a nuclear system. The INL facility will include renewable generators, power systems, energy storage, and both thermal and electrical energy users that are physically integrated with an electrically heated loop that emulates thermal energy input from a nuclear fission reactor. System tests will be designed to demonstrate coordinated and efficient multidirectional transient distribution of electricity and heat for power generation, storage, and industrial end uses. Successful electrically heated demonstration would be followed by future nuclear demonstration via an existing large scale LWR that could be repurposed for hybrid application or a newly built small modular reactor planned for initial operation in the mid 2020s [10]. This section briefly describes the current status of test facility design and outlines the program vision to use advanced computational tools in conjunction with experimental demonstration to definitively show how this new paradigm for nuclear and renewable energy system design can become a reality in both small scale, distributed energy systems and in large scale centralized systems.

A Dynamic Energy Transport and Integration Laboratory (DETAIL) is being designed for installation within the Energy Systems Laboratory at INL to demonstrate integrated system operation. Fig. 6 provides an overview of the planned test facility components and integration. The overall objective for the DETAIL facility is to demonstrate simultaneous, coordinated, and efficient transient distribution of electricity and heat for power generation, energy storage, and industrial end uses. A dynamically controlled, electrically heated thermal energy production and distribution system that would emulate energy input from a reactor has been designed. In this system the heat production from nuclear fuel would be simulated using electrical heating and sophisticated control algorithms to provide simulation of system dynamics within a hardware system. When complete, the combined DETAIL facility would provide demonstration of real time integration with the electrical grid, renewable energy inputs, thermal and electrical energy storage, and energy delivery to an end user. As such, an integrated energy network can be operated with hardware in the loop to improve understanding of how to optimize energy flows while maintaining system stability and efficient operation of all assets in the system.

Many components within the DETAIL facility shown in Fig. 6 are already installed and operational. These include several microgrid components, such as the digital real time simulator stations that represent power systems in the grid, wind energy input, solar photovoltaics, chemical flow batteries, and electric vehicle (EV) and battery charging. A 25 kW_e high temperature steam electrolysis (HTSE) for hydrogen generation has also been installed and is undergoing initial system testing. Fig. 7 shows the current state of the laboratory facility in Spring 2018. Electrically heated nuclear reactor emulation systems and thermal energy distribution infrastructure are currently in final design and are expected to be installed in 2019.

A high pressure, high temperature water flow loop has been designed for deployment in DETAIL and is awaiting final decision to procure and install. The high pressure water loop would operate at Pressurized Water Reactor (PWR) conditions, including both forced convection and natural convection loops. The PWR emulation loop is the first of three thermally coupled flow loops that would comprise the full Advanced Reactor Technology Integral System Test (ARTIST) subsystem, shown on the left side in Fig. 6. As envisioned, the ARTIST facility would ultimately include emulation of multiple reactor system concepts, including a high temperature helium loop and a liquid salt loop, in addition to the PWR loop. The loop would be thermally integrated with the collocated energy systems including a thermal energy transport loop, thermal energy storage system, and energy users. The electrically heated flow loop would be dynamically controlled to simulate nuclear fuel behaviour under normal and off–normal operating conditions.

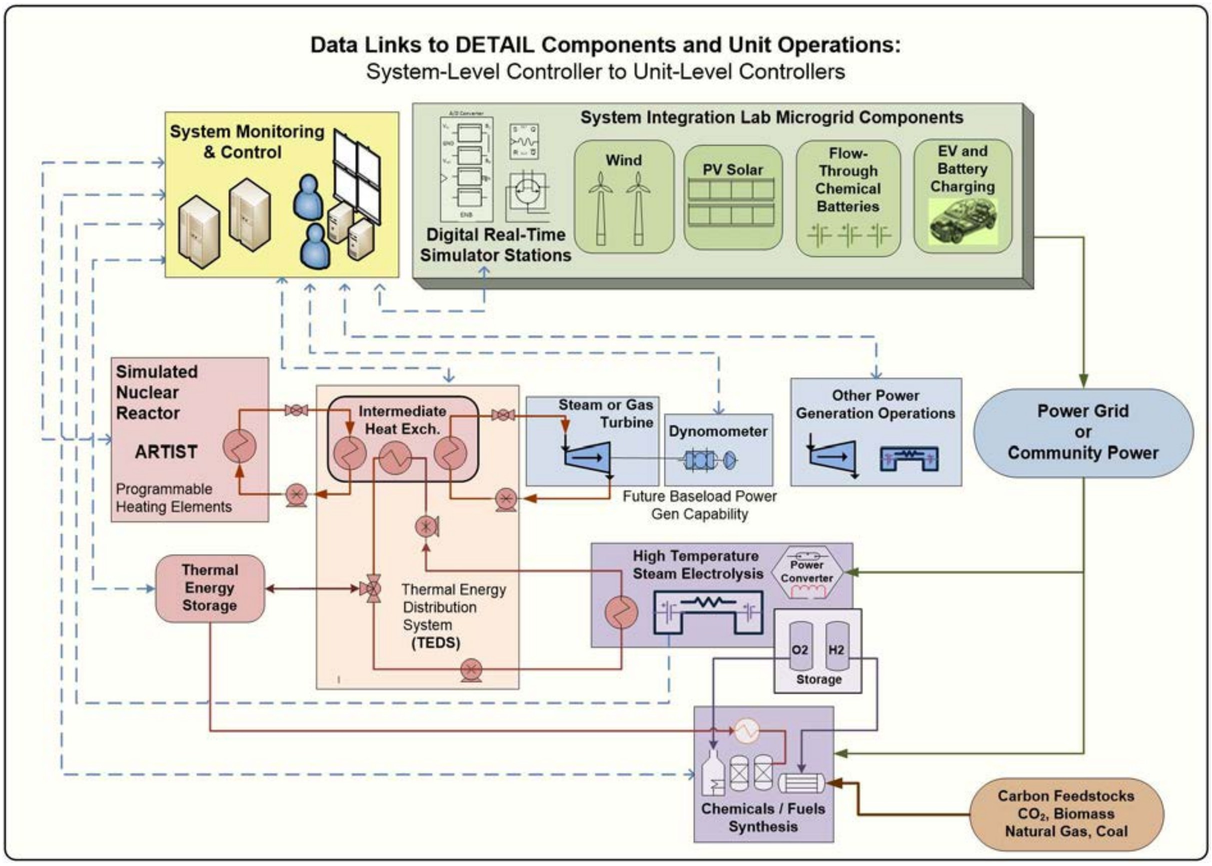

FIG. 6. Integrated systems test facility overview, showing both currently installed and planned components.

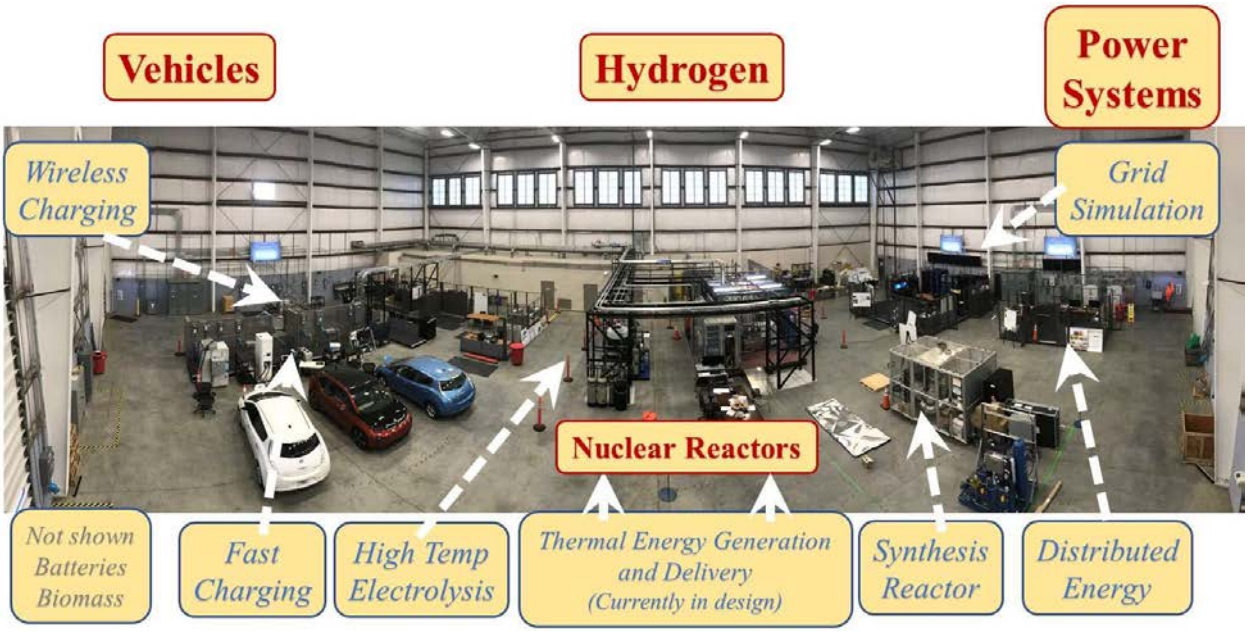

FIG. 7. Status of the DETAIL test facility as of Spring 2018; additional hardware has been installed for hydrogen generation in Summer 2018, and electrically heated nuclear reactor emulation systems are currently in final engineering design.

A Thermal Energy Delivery System (TEDS) is needed within the DETAIL facility to test heat transfer components, distribution systems, instrumentation, and control infrastructure that can be monitored and controlled for hybrid generation of electrical power and/or non-electrical products. All subsystems within DETAIL are designed to operate either independently or as a part of an integrated system to demonstrate component operation, to develop and validate thermal energy transport models and control systems, and to study thermal energy inertia and storage. Within the integrated system, TEDS would be connected to the Digital Real-Time Simulator test platform to develop and demonstrate monitoring and control systems and to investigate real time, hardware in the loop response characteristics relative to grid operations. The system can be used to characterize thermal energy inertia and thermal energy management relative to the interoperability of a nuclear plant, power generation, and industrial heat applications. TEDS operation will additionally provide data to validate physics based computational models that can be used to support scale up of hybrid energy systems for demonstration with operating (fuelled) nuclear plants. TEDS is undergoing final engineering design and is expected to be procured and installed in 2019.

4. INDUSTRIAL ENGAGEMENT AND PATH FORWARD

Industrial engagement is a crucial element in the N-R HES Program. Involvement of industry — namely utilities, transmission system operators, reactor vendors and developers, and industrial energy users — in the R&D activities ensures that the DOE laboratory led research is relevant to industry needs and is grounded in realistic scenarios for subsystem integration, operation, and control. The N-R HES Program is establishing strong ties with industry through a Utility Advisory Committee, Cooperative Research and Development Agreements (CRADAs) and Strategic Partnership Projects (SPPs), and workshops designed to bring industrial stakeholders, researchers, DOE, and other government organizations together to identify energy systems development needs. RD&D commences with technology development, systems integration and co-simulation/testing, and precommercial demonstrations to reduce the risk of building and operating hybrid energy systems that derive a large portion of their energy from nuclear fission. This stage would be followed by technology demonstration with commercial partners, either those developing novel small modular reactors as described in reference [10] or utilities operating the current LWR fleet. The N-R HES program is actively bringing together nuclear technology developers and industrial users of nuclear energy to establish a new paradigm for industrial energy production and use alongside traditional electricity generation.

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SYNERGY OF NUCLEAR AND RENEWABLE AQABA CITY PATHWAY TO NET-ZERO EMISSIONS

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Abstract

The Hashemite Kingdom of Jordan plans to build a Nuclear Power Plant (NPP) to ensure security of energy supply, reduce dependence on imported oil and gas, and to meet future increase in energy demand. Jordan commenced its efforts to energy diversification in 2007. The fact that 98% of Jordan's energy was imported (in 2007) was not very comforting on all levels, and dependence on one source of energy for electricity was too risky. It is every country's desire to be energy independent or at least well diversified to a point that energy ripples are well mitigated. Jordan laid down the foundations for the diversification of energy in 2007. As a small economy with few natural resources, reliance on imported energy (oil and natural gas) come coupled with exposure to both supply risk and price risk. The Jordan Atomic Energy Commission (JAEC) established under Law 42 in 2007 was established to lead the development and implementation of nuclear strategy and to manage the nuclear program in Jordan. JAEC oversaw the implementation of several key and notable projects in Jordan including the Sub-Critical Assembly, the exploration of uranium in Central Jordan and The Jordan Research and Training Reactor (JRTR) — Jordan's first nuclear reactor. Current projects JAEC is overseeing to include the uranium mining project in Jordan and the nuclear power plant projects under development including SMRs.

1. INTRODUCTION

The Hashemite Kingdom of Jordan is located in the Middle East (north of Saudi Arabia, east of the River Jordan, west of Iraq, and south of Syria). Except for the 25 km coastline in the south, Jordan is landlocked with a semi-arid climate (mountains in the north and west, and deserts in the south and east). Jordan is officially an upper middle income country, that is service oriented. Due to the size of the economy and the turbulent region (especially in the last 5 years), Jordan's economy has been exposed to some regional risks and weathered some storms.

Jordan commenced its efforts to energy diversification in 2007. The fact that 98% of Jordan's energy was imported (in 2007) was not very comforting on all levels, and dependence on one source of energy for electricity was too risky. It is every country's desire to be energy independent or at least well diversified to a point that energy ripples are well mitigated. Jordan laid down the foundations for the diversification of energy in 2007. As a small economy with few natural resources, reliance on imported energy (oil and natural gas) come coupled with exposure to both supply risk and price risk. In 2012, and in the advent of the Arab Spring, exactly that happened.

The interruptions of natural gas supplies from Egypt to Jordan led the government to switch immediately to the importing of the much more expensive (heavy fuel oil, diesel oil). This meant an anticipated debt burden that could not be passed on the consumer. Albeit Jordan's efforts to diversity and the decision to embark on an energy diversification program in 2007, 2011–2012 was just too soon for any efforts of the diversification to bear fruit. This led Jordan to incur billions in losses and even more on the public debt.

Electrical load in Jordan has been consistently growing over the last nine years. In spite of the economic slowdown due the regional turmoil, and all the efforts of the government's diversification efforts, the dependence is still overwhelming on foreign resources of energy (at over 95%).

2. NUCLEAR PROGRAM IN JORDAN

The Jordan Atomic Energy Commission (JAEC) established under Law 42 in 2007 was established to lead the development and implementation of nuclear strategy and to manage the nuclear program in Jordan. JAEC oversaw the implementation of several key and notable projects in Jordan including the Sub-Critical Assembly, the exploration of uranium in Central Jordan and The Jordan Research and Training Reactor (JRTR) — Jordan's first nuclear reactor. Current projects JAEC is overseeing include the uranium mining project in Jordan and the nuclear power plant projects under development including SMRs.

Jordan plans to build a Nuclear Power Plant (NPP) to ensure security of energy supply, reduce dependence on imported oil and gas and to meet future increase in energy demand. Vision 2025 sets the target for generation of electricity from nuclear energy to be around 15% from the total mix, and JAEC is working diligently to have this materialize. The current situation for Jordan is overreliance on imported energy (currently standing at around 95%). This is too high.

Jordan's revised energy mix sets no energy source with more than 50% of generation (national security). The addition of nuclear power will help to alleviate a predicted energy shortage of around 700 MWe by 2027 (conservatively). In addition, nuclear energy is anticipated to help ensure stable pricing of electricity and to contribute to the economic growth of Jordan.

Currently, JAEC is working with several leaders in the nuclear field in assessing the technologies, viability of the technologies in Jordan, and the long term sustainability and feasibility of deployment. Jordan is doing on two parallel tracks. The first track is based on a large nuclear reactor. This is basically the construction of a pressurized water reactor with around 1000 MWe net output on a suitable selected site in Jordan — which has already been identified. The second track is a Small Modular Reactors (SMRs) track. This track involved the assessment of SMR technologies, shortlisting of the most suitable for Jordan according to criteria set forth based on best practice. Following, a detailed feasibility study will be conducted for the shortlisted technologies to select the most optimal technology.

3. POTENTIAL FOR ENERGY GENERATION SYNERGY IN JORDAN

Jordan's primary energy distribution is currently around broken down roughly to around 50% for transport and 50% for all other uses of energy (Fig. 1, generation — all, industrial, etc.). Exploring the potential for synergy has to be considered taking into consideration multiple domino effect that can benefit other sectors and need to.

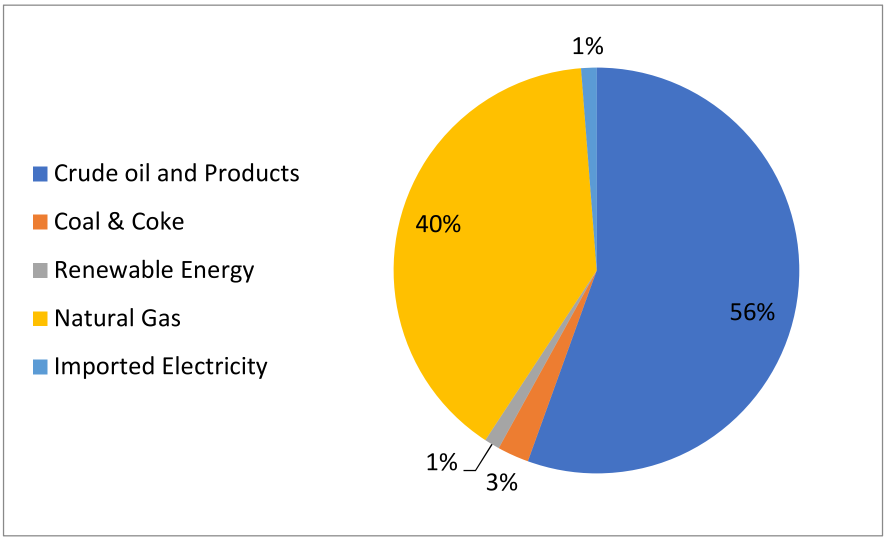

FIG. 1. Primary energy consumption in Jordan in 2017 [1].

As far as energy synergy, primarily nuclear/renewable, the major benefits for such a coupling include:

- Green House Gases (GHG) reduction;
- Low carbon zero emission energy generation;
- Integration of nuclear with renewables will:
  - Amplify the advantages possessed by both individually;
  - Increase the options available for meeting energy needs.

In further exploring the advantages and how they could be transposed to Jordan's energy strategy (2025) of introducing nuclear (15%) and increasing renewables (to 10%), specific sectors have to be targeted and set as objectives for development to optimize and thus maximize from the overall advantages possessed by this integration.

Energy generation for variable generation sources such as renewables for optimal and effective utility scale deployment needs to be addressed. Usually the solution is quite expensive, either coming in the form of spinning reserve on the system or batteries that cost more upfront (both in terms of increased overall system requirements and battery costs) with the latter not delivering baseload performance as do other baseload generation sources. Nuclear on the other hand is a workhorse, with systems in operation reaching 95% availability. High upfront costs mean that the revenue streams needs to be continuous to pay the debt to the lenders and returns to the investors. Running at 50% capacity is economical.

The synergy of both in Jordan can be a perfect solution, as it delivers on the basic advantages of both and more important, Jordan specifics and requirements. Jordan needs electricity, set a strategy to rely more on local energy as opposed to imported intermittent fuels, considers water a national security issue of the highest priority. This taken into consideration, it is a matter of how to proceed with a viable implementation of an integrated system that generates optimally meeting loads (day and night), desalinated water and addresses transportation with a solution or a multitude of solutions.

To deploy nationwide could be a second step. What is proposed is a solution for deployment in one city in Jordan to be a pilot. We propose the coastal city of Aqaba, for several advantages that it possess (potential city for the construction of the HTR nuclear power plant, small in population and size, special economic zone city).

4. AQABA CITY — ENVISAGING A NET-ZERO EMISSIONS FUTURE THROUGH ENERGY SYNERGY

4.1. Aqaba today

Aqaba is the only coastal city in Jordan and the largest city on the Gulf of Aqaba. It has a coastline of 26 km. The city's population is around 150 000, and it covers a land area of 375 km^2. As the only port in Jordan, Aqaba is a key city in the development of the Jordanian economy. In addition to trade and tourism, Aqaba is a hub for the majority of freight coming in and out of Jordan (serving both Jordan and other countries in the region).

As the only coastal city, it comes naturally to look to Aqaba for energy and desalination. Jordan is a resource poor country and the Arab Spring/gas interruptions of 2011–2013 wreaked havoc on the Jordanian economy. The economy is still suffering today from the losses incurred in those three years as mentioned earlier. Jordan has setup an LNG Jetty in the coastal city and energy (generation) costs in 2014 stabilized. This is however only one part of the equation.

The long term strategy of Jordan for energy is to diversify energy sources. Over dependence on imported energy especially fossil fuels has proved disastrous in the long run. Looking for oil and gas has led to nowhere; regional partnerships are not as solid as they are elsewhere. Aqaba as proposed might have an answer.

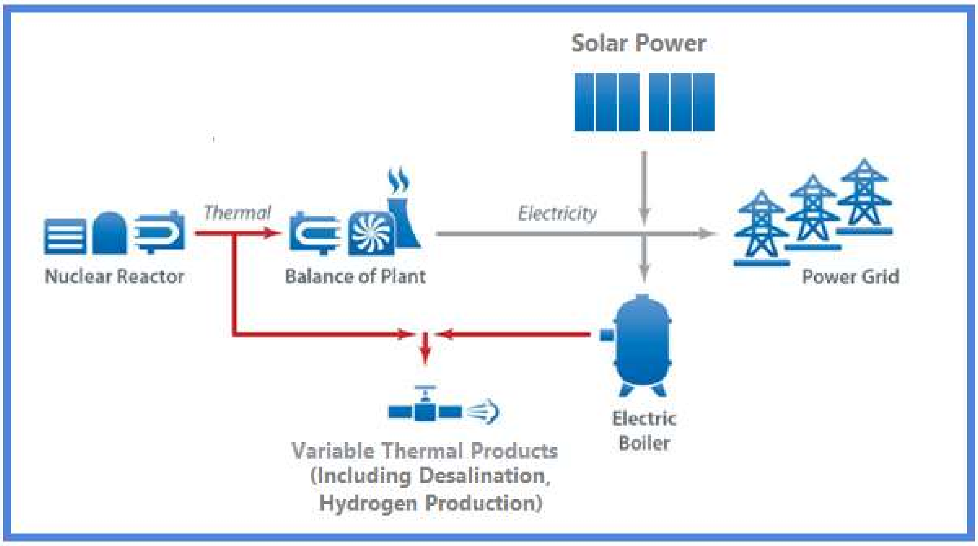

FIG. 2. Proposed synergy system incorporating nuclear/solar (PV).

Fig. 2 shows a general integration of nuclear with solar and the synergy of having both work in unison.

In the diagram above, there are three distinct components. The first is electricity generators, the second is electricity consumers, and the third is alternative industry consumers (these make the synergy worthwhile and of added value).

4.2. Energy generation and electricity consumer

Independently, nuclear and renewable sources generate electricity in a completely different manner. One is baseload made to work 24/7. One is intermittent or variable depending on the terminology one prefers to use. Each alone has its ups and down. Together though, they complement each other. The daily load use in Jordan always starts to increase to increase from 9 and peaks at 11–2. This is when PV is performing at its best on the system.

As far as an NPP, and as a coastal city, Aqaba is the first destination to search for an optimum site to construct an NPP. The main for this is the cooling water. Inland NPP are built but the requirements are different. It is by the coast that the first preference always lies.

Currently, JAEC is in discussions with partners to evaluate the potential for deploying a High Temperature Gas Cooled Reactor (HTR) in Aqaba. JAEC is in discussions with other vendors but the HTR looks very promising. Several sites have been identified for this purpose. More extensive studies will be conducted.

As a regulated market, electricity is all sold to the off taker. Potentially, discussions on selling to other third parties outside Jordan can be made, but up to now this is a regulated market and all electricity is sold to National Electric Power Company (NEPCO).

4.3. Water desalination

As Jordan is one of the poorest countries in the world, in terms of water scarcity, finding new water sources or solving the ongoing problem is a priority for every government. Desalination was not a topic of discussion in Jordan 10 years ago, today it is and high on the agenda. It is not a matter of if, but more a matter of how much, and when.

Jordan has built the Disi Water Conveyance which transports 100 000 000 m^3 from the Disi aquafers to Amman and the Northern Cities for 25 years (it commenced 2013. The aim of is to continue pumping until there is a suitable replacement via desalination (Red Sea–Dead Sea Canal). Desalination requires a lot of energy or high temperature steam. Well both are available, within the system proposed for the city in Aqaba.

Desalination is very energy intensive as is. For Jordan, and at the time of project competition it required 4% of Jordan’s energy (between pumping and transportation). The Ministry of Water and Irrigation is building new RE plants to offset for the high running costs of the pipe. New mega water project will need energy other than from conventional. Nuclear/Renewable combination might just be the answer.

4.4. Industry and transportation

It is in the industrial uses and transportation that truly energy synergy can be applied, and to its fullest. This is where both nuclear and renewable will find a common buffer to work. At the end, it is the guarantee/optimization of revenue generation that will lead the way for projects to realization. With a synergy vis à vis much needed industrial (targeted) and transportation, the rollout of NPP and renewable power plant will definitely not stop at one.

Industrial uses of heat, nuclear energy is an excellent source of process heat for various industrial applications including synthetic and unconventional oil production, oil refining, biomass based ethanol production and hydrogen production. Aqaba is focusing its efforts on the construction of an HTR now. As light water reactors produce heat at relatively low temperatures and thus are considered unsuitable for many industrial uses, HTR on the other hand produce heat at over 700°C.

At 50% of TOE (Total Oil Equivalent), and any percent drop is going to be beneficial to the economy of Jordan. As a tourist destination, transportation should be incentivized on a city wide scale for residents to purchase EV vehicles. As of 2019, EV car models are entering the market and as far as the experts go, this trend is not stopping (VW alone is investing $40 billion by 2022/$8 billion a year). EV with the electricity coming from gas generators is of no use to the environment.

4.5. Energy synergy

Thinking big is thinking good, but energy is not like that. The proposed system for Aqaba envisages the production of electricity, desalinate water, and produce heat for industrial uses. This primary system is coupled with the different systems together (users) to maximize the advantages possessed by each individually. Whilst NPP will produce electricity all the time, in the hybrid system the thermal steam is what will be required rather than MWe to drive industry and desalinate water.

The supply of energy/demand of the users' optimization curve will dictate where the load factor is at a certain time. PV will be off at night, so no energy will be coming from PV at night, so will the demand curve from household as they form 22% of the energy (43% of the electricity use) in Jordan, and so on.

The benefits include overcoming the variable generation of renewables as the baseload nuclear (depending on the load and the system), will produce electricity as a priority. Once the electricity from solar is flowing into the system, an excess then triggers a switch to direct thermal. It has to be made clear that in a regulated market like Jordan, the aim objective of the synergy will be to optimize the efficiency and allocation of both systems and not the selling price.

The selling price is determined by a PPA and not the market (unregulated markets). However, it makes sense that if only 300 MWe is required in the grid system, 750 MWth be used for industrial applications.

5. NET-ZERO EMISSIONS CITY: AQABA AS A PROOF OF CONCEPT

Starting with electricity generation (Nuclear (proposed HTR)/PV hybrid), developing on to EV and proposed hydrogen vehicles for public transport and light freight, the development and design of such a city as a proof of concept in transformation should only leave the airport and marine port that are the major contributors of CO_2 emissions on the CO_2 balance sheet of the city [2].

Net-zero emissions is not a novice idea and several cities have now put it before them to be carbon neutral. This will include all new construction to be net-zero with changing the structure of the energy system being a top priority. There is a common characteristic amongst cities aiming for carbon neutrality. Size and population is one of them. Most of the cities aiming for that goal are in or around 100 000. Cities with millions present challenges that dictate to set objectives such as carbon neutrality to be long term goals. Albeit presenting challenges, Aqaba possesses opportunities, if thoroughly analysed, might outweigh these challenges.

Aqaba is in the right place, and of the right size, and possesses the right characteristics for a Net-Zero Emissions Proof of Concept (NZEPC) roll out in Jordan. It will take a while for a city to achieve NZEPC, but really this is not the objective. Albeit Aqaba's size being a definite advantage, it is the synergy of both nuclear and renewables, not just in the generation, but from generation going on to consumer (the main goal) contained all in one with the industry and providing added value where it is needed (desalination) is where Aqaba will play a key factor, as special economic zone able to implement projects swiftly and attract investments without the bureaucracy.

No matter the challenge that are involved, it must be rolled out with more than just the generation side in mind. Transportation, heating, industry, and freight must be considered but on a small scale so that this opens the door for a larger and more systematic implementation. A larger implementation will not necessarily consider Jordan as net-zero emissions, but the process that occurring in Aqaba will have within it, enough lessons learned so that mistakes are corrected, and improvements made[1] [3].

6. CONCLUSION

The aim of the study is to explore the potential for Jordan's endeavours in future energy generation, and the best means to maximize the added value, and if there are benefits that can be of added value to any synergy and whether it makes sense. Jordan will need 600 MWe by 2025, and another 700 by 2032. Jordan's already is exhausting its fresh water resources and is dire need to develop an infrastructure for sustainable fresh water, and a lot of it. Interruptions of fuel sources have battered the Jordan economy and are only getting worse every time. Exploring options to solve each issue has been, up to this point, independent of the others.

Focusing on Jordan's main issues at hand, the envisioned solution paves the way for a different kind of thought process. This current situation requires a creative solution to overcome the hurdles. Investigating all the practical solutions and focusing on synergy between the generations technologies is the first step, followed by an integrated solution within the system to reduce the water deficit in water resources by desalination (reject heat for efficiency). This will be optimized with the integration slowly of industrial and transportation to forma a complete system.

The first step will be working within Aqaba and maximizing the city potential in the city by the city. Following the pilot project will be moving this to the full scale implementation to the rest of Jordan. Aqaba is a growing city and has been using deep aquifer water. This is not sustainable in the long term. If economic prosperity and growth is to occur in a city, energy is a paradigm component.

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[1] Jordan has just recently issued several licenses for building a small PV station (smaller than 2 MW_e) intended specifically to be coupled with charging EV cars for a private company (licenses for charging points also issued) and issued licensed for EV charging points for another Jordanian Company. This is also an ongoing trend.

CHALLENGES AND POTENTIAL BENEFITS OF COGENERATION IN ROMANIA – THE IMPACT ON ENERGY COST AND DECARBONIZATION

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Abstract

Cogeneration is addressed in this study and applied to the national Romanian energy system in order to achieve a higher decarbonization and more cost effective energy production. Three main cases have been taken into account, each one having four scenarios of greenhouses gases (GHG) emission reduction. In the first case, no cogeneration is taken into account, in the second one the cogeneration is envisaged for some technologies without any additional costs and in the third case the introduction of cogeneration is accompanied by a 20% increasing of the investment cost applied to the same technologies as in the second one. The four scenarios of GHG emission reduction are defined as follow: Basic scenario with no GHG constraints, GHG50, GHG75 and GHG90 scenarios with 50%, 75% and 90% GHG emission reduction, respectively. The IAEA MESSAGE tool was used to set up the energy model and to optimize it. The paper's results show that 90% reduction of GHG emission by 2050 is not sustainable for Romania. The main benefit regarding cogeneration utilization in Romania has been found to be assuring a more cost effective electricity production in scenarios with strong GHG restrictions, also helping to meet the emission targets. The main challenges come from the actual trend of decommissioning existing cogeneration units due to environmental issues along with high losses inside of a very old heat distribution network, these leading to a customers' migration to individual heating solutions. The presence of nuclear energy in all scenarios with shares of up to 20% in the total electricity production shows its pillar position in the future Romanian energy system development, this allowing for working together with renewable intermittent energy sources, these last being increasingly developing.

1. INTRODUCTION

The Romanian energy sector faces challenges coming from the last two decades. On one side, there is a need to replace the old fossil fuel based power plants by new ones with low carbon emissions; on the other side, there is still a need to build new stable and reliable electricity generation systems in the context of a large energy market penetration by intermittent renewables like wind and solar sources. Fortunately, Romania has a diversified energy portfolio with comparable shares of hydro, nuclear and wind — this opening the way to establish synergies between them. Unfortunately, the majority of intermittent renewable were built in the Dobrogea region, where the Cernavoda NPP is located, this putting additional pressure on the local grid in order that electricity to be supplied to customers. In order to deal with actual energy challenges, the Romanian Government updated the Energy Strategy in December 2016 [1]. The Romanian energy strategy foresees a few key objectives as follow:

- Reducing energy poverty and protection of vulnerable consumers;
- Assuring the security of energy supplying, clean energy and competitiveness of the energy market;
- Modernization of the governance of the energy system.

The above mentioned objectives should be assured through the following actions:

- Renewal and refurbishment of actual electricity capacities;
- Developing natural gas network and supplying;
- Keeping the main role of biomass in rural domestic heating;
- Developing high efficiency cogeneration and modernization of actual Centralized Heat Distribution System (CHDS);
- Improving the energy efficiency of buildings.

Romania has accomplished the obligations undertaken for 2020 regarding increasing the share of Renewable Energy Sources (RES) in the total energy mix. Thus, at the end of 2015 the RES share was 26.3%, compared to a 24% target [1]. In order to achieve higher decarbonization and more efficient energy use, cogeneration is envisaged in this study and applied to the national Romanian energy system. Energy cogeneration is a process by which a plant simultaneously generates two forms of energy, usually electricity and heat. In this respect, some developing scenarios of the national energy system are proposed and evaluated from the point of view of sustainability.

1.1. The state of the Romanian energy system

Romania is the only significant producer of hydrocarbons in Southeast of Europe. The annual production has consistently diminished in the last decade, reaching 3.8 million tons of crude oil and 10.8 billion m^3 of natural gas in 2015. The proven reserves of crude oil were 38.4 million tons in 2015 and the gas ones of 101.4 billion m^3 [1].

Natural gas accounts for about 30% of domestic primary energy consumption. This important share is explained by the relative high availability in domestic resources, through a reduced impact to the environment and through the ability to balance electricity from intermittent renewable energy sources (RES) like wind and solar.

Coal is a basic component of the energy mix, acting as a pillar of Romanian energy security. In extreme weather conditions, both summer and winter, coal accounts for one third of electricity demand. Romania has total reserves of 12.6 billion tons lignite, concentrated in the Oltenia mining basin. Coal resources in operation are about 986 million tons [1].

Uranium is another strategic resource of Romania. Over the last two decades Romania has proved a solid operating experience of a full cycle of natural uranium, developed based on CANDU technology. Uranium dioxide is produced at FCN Pitesti, a Nuclearelectrica subsidiary, by refining uranium extracted from indigenous production. In 2016, The National Uranium Company entered the process of restructuring, with the prospect of exploiting new indigenous uranium deposits. Nowadays, Nuclearelectrica purchases raw material from foreign markets in order to produce the nuclear fuel [1].

The instantaneous electricity production in Romania is shown in Fig. 1 [2].

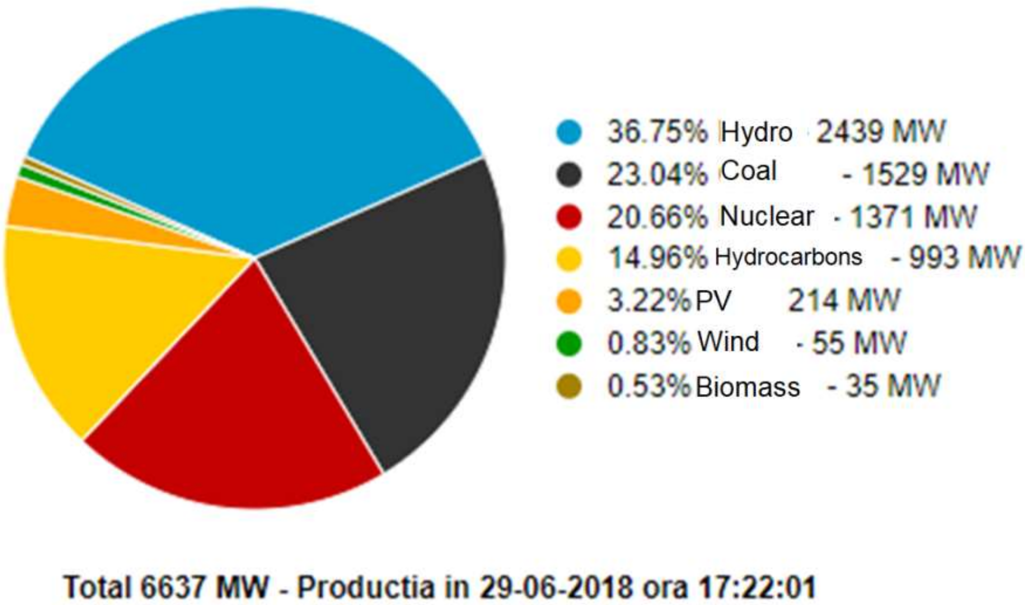


FIG. 1. Electricity production [2].

The heat consumption in Romania was about 20 200 MWyr in 2015 [1]. Only 16% of the total heat demand is distributed through the Centralized Heat Distribution System (CHDS), the rest being supplied by gas heating (39%) and biomass (especially wood, 45%).

2. SCENARIOS AND MESSAGE MODEL DESCRIPTION

Three main cases have been taken into account in this paper, each of them having four scenarios of greenhouses gases (GHG) emission reduction. In the first case, no cogeneration is taken into account; in the second one, cogeneration is envisaged for some technologies without any additional costs; in the third case, the introduction of cogeneration is accompanied by a 20% increasing of the investment cost applied to the same technologies, as in the second case. Inside of every case there are four scenarios of GHG emission reduction as follow: a Basic scenario with no GHG constraints, GHG50, GHG75 and GHG90 scenarios with 50%, 75% and 90% GHG emission reduction by 2050, respectively. The three cases with their identical scenarios are summarized in Table 1.

TABLE 1. CASES AND SCENARIOS' DESCRIPTION

CASE NO.	CASE DESCRIPTION & ACRONYM	SCENARIO NAME	SCENARIO DESCRIPTION
1	No cogeneration "*NoCog*"	Basic GHG50 GHG75 GHG90	No GHG reduction 50% GHG emission reduction 75% GHG emission reduction 90% GHG emission reduction
2	With cogeneration, no additional costs "*withCog*"	Basic GHG50 GHG75 GHG90	No GHG reduction 50% GHG emission reduction 75% GHG emission reduction 90% GHG emission reduction
3	With cogeneration, plus 20% larger investment costs "*withCog+20%inv*"	Basic GHG50 GHG75 GHG90	No GHG reduction 50% GHG emission reduction 75% GHG emission reduction 90% GHG emission reduction

The modelling of the Romanian energy system was performed using the IAEA MESSAGE tool [3]. MESSAGE (Model for Energy Supply Strategy Alternatives and their General Environmental Impacts) is one of the IAEA software tools, designed for setting up models of energy systems for optimization. The Romanian energy system modelling started in 2017 in the frame of an IAEA coordinated training course held in Pitesti, Romania and preliminary results regarding National Determined Contribution (NDC) to climate change mitigation were presented in Vienna at the 14th INPRO Dialogue Forum [4]. In the last year, the model has been updated with more realistic data regarding GHG emissions in Romania. It should be mentioned that only carbon dioxide (CO_2) was taken into account, this gas being the main contributor to GHG emission.

The actual MESSAGE model has the following characteristics and assumptions:

- The modelled period is 2011–2050 divided in 39 intervals, every of them having one year length with the base year 2010;
- Electricity demand increases almost at a constantly rate from 4800 to 8500 MWyr [1];
- Heat demand is decreasing from 20 000 MWyr in 2011 to 15 000 MWyr in 2050;
- Introducing advanced coal and gas based power plants (Coal_PP_new, Gas_PP_new) with low emissions (0.4 ktons CO_2/MWyr, about five times lower than actual ones);
- 1400 MW addition in nuclear power (other 2 CANDU Units in Cernavoda NPP by 2025 and 2030, CANDU34 technology);
- A minimum of 50% share of nuclear installed capacity was supposed to be operated in order to comply with nuclear safety requirements;

— Demand for oil products is projected in [1] and decrease from 6175 MWyr (approximately 9 million tonnes) to 3.5 million tonnes (2422 MWyr) at the end of the modelled period;
— All oil derivatives are burned with the same emissions per unit of energy, both in industry and in transportation;
— Up to 1000 MW new pumping storage hydro power plant will be commissioned by 2020 (Hydro_new technology);
— Moderate increasing in share of renewables (wind, solar, hydro);
— Decommissioning up to 3000 MW in old coal based power plant by 2025.
— No uranium import, no CO_2 emission taxes, no CCS technologies.

The technology chain in the MESSAGE model is shown in Fig. 2.

Level	Energyform	Producers	Consumers
Resources	Coal		Coal_Extr
	Gas		Gas_extr
	Oil		Oil_Extr
	Uranium		U_conv
	Biomass		Biomass_Heat Biomass_Heat_LowEmiss
Primary	Coal	Coal_Extr	Coal_PP Coal_PP_new
	Gas	Gas_extr	Gas_PP Gas_PP_new Gas_Heat
	Oil	Oil_Extr Oil_imp	Oil_Heat Oil_TD
Front-end	U_conv	U_conv	U_fuel
	U_fuel	U_fuel	CANDU_12 CANDU_34
Back-end	fromCore		Fr_core12 Fr_core34
	dummy	Fr_core12 Fr_core34	
Secondary	electricity	Coal_PP Coal_PP_new Gas_PP Gas_PP_new CANDU_12 CANDU_34 Hydro_1 Hydro_2 Hydro_new Wind_F PV	Ele_TD
	heat	Oil_Heat Biomass_Heat Biomass_Heat_LowEmiss Gas_Heat	Heat_TD
Final	electricity	Ele_TD ADD_Ele	
	heat	Heat_TD ADD_Heat	
	oil	Oil_TD	

FIG. 2. The MESSAGE technology chain.

There are 6 energy levels (Resources, Primary, Front-end, Back-end, Secondary and Final) along with 8 main energy form linked through the 28 technologies. The nuclear technology modelling is taken from the National Project on “Nuclear Energy System Assessment in Romania using INPRO Methodology”, 2014–2015. The technologies that apply to cogeneration are Coal_PP_new, and

Gas_PP_new. They have 44% and 38% electrical efficiency, respectively, along with the same 40% efficiency of heat supplying as secondary output. A summary of relevant technology characteristics is presented in Table 2 along with their GHG (CO_2) emissions.

TABLE 2. RELEVANT TECHNOLOGY PARAMETERS

PARAMETER	TECHNOLOGY NAME						
	Coal_PP	Coal_PP _new	Gas_PP	Gas_PP_ new	Biomass_ Heat	Biomass_Heat_ Low Emiss.	Oil_ Heat
Efficiency (%)	38	44	38	38	80	90	100
Capacity factor (%)	95	95	95	95	95	95	95
Operation time (%)	80	80	80	80	95	95	90
Construction time (years)	3	4	3	3	2	2	2
Lifetime (years)	45	40	40	40	40	40	40
Investment costs ($/kWe)	1000	1050	1000	2000	800	2000	1000
O&M variable costs ($/kWyr)	3	2	2	4	12	12	3
O&M fixed costs ($/kWe/yr)	16	15	17	17	10	10	10
Existing capacity in 2011 (MW)	6000	2000	6000	1000	5000	-	1500
CO_2 emission (ktons/MWyr)	3.12	0.4	1.86	0.37	2.5	0.5	2.2

PARAMETER	TECHNOLOGY NAME						
	Hydro 1	Hydro 2	Hydro_new	Wind_F	PV (Solar)	CANDU 12	CAND U 34
Efficiency (%)	97	97	98	100	100	33	33
Capacity factor (%)	100	100	85	40	50	95	90
Operation time (%)	80	80	95	30	40	98	98
Construction time (years)	4	4	5	2	2	3	4
Lifetime (years)	70	70	70	25	20	45	40
Investment costs ($/kWe)	500	400	3000	1200	4000	500	4000
O&M variable costs ($/kWyr)	1	2	2	2	5	8	8
O&M fixed costs ($/kWe/yr)	15	15	20	10	12	55	55
Existing capacity in 2011 (MW)	2700	3800	6000	1000	5000	1400	0

3. ELECTRICITY AND HEAT PRODUCTION

Electricity production in Case 1 (no cogeneration) is presented in Figs 3 to 6 for the corresponding GHG emission reduction scenarios. The pictures were captured from MESSAGE output and electricity is expressed in MWyr with respect to the time (the years of period 2011–2050).

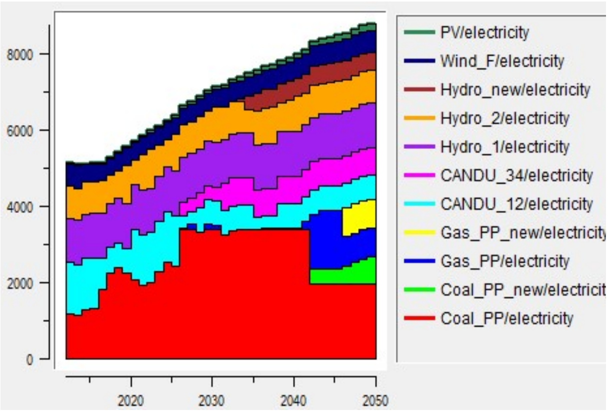


FIG. 3. Electricity production (MWyr) by time, Case 1 (no cogeneration), Basic scenario.

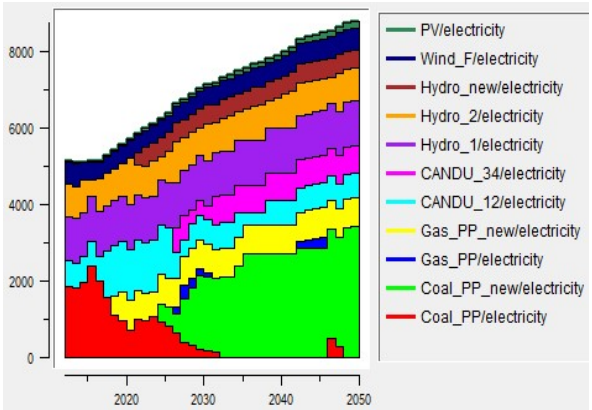


FIG. 4. Electricity production (MWyr) by time, Case 1 (no cogeneration), GHG50 scenario.

In the Basic scenario (with no GHG restrictions) the system uses predominantly cheaper technologies based on coal (see Fig. 2, red colour), while in the rest of the three scenarios a shift to the advanced coal energy technology (Coal_PP_new) can easily be observed. With other words, as the restrictions on GHG emissions become harder, the system starts to use more expensive technologies, but having lower CO_2 emissions.

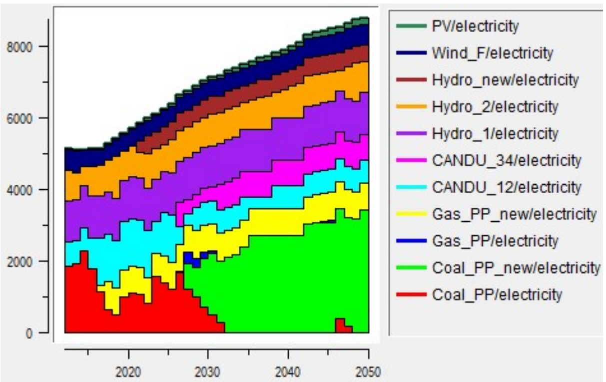


FIG. 5. Electricity production (MWyr) by time, Case 1 (no cogeneration), GHG75 Scenario.

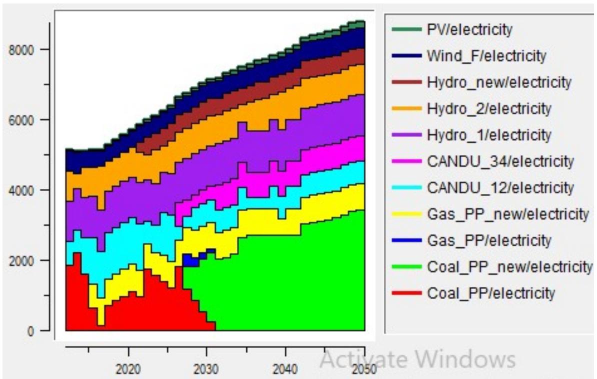


FIG. 6. Electricity production (MWyr) by time, Case 1 (no cogeneration), GHG90 Scenario.

As was mentioned earlier, the single greenhouse gas species considered in analysis was CO_2. Nuclear energy is present in all scenarios with average shares up to 20% of the total electricity production.

Heat production in Case 1 (no cogeneration) is presented in Figs 7 to 10.

It should be mentioned that the heat demand is fully satisfied only in the Basic scenario along with the next two ones. In the last decade of the GHG90 scenario the system cannot meet the heat demand due to the GHG emission restrictions which are too strong (see the white region under the dotted black line in Fig. 10). As a result, it is considered that a 90% reduction of GHG emission till 2050 is not sustainable for Romania.

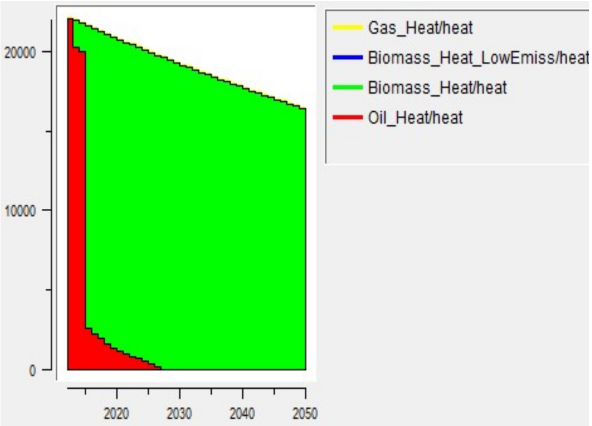


FIG. 7. Heat production (MWyr) by time, Case 1, Basic scenario.

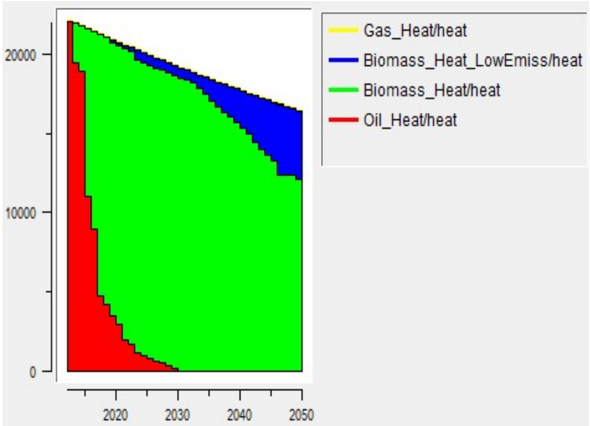


FIG. 8. Heat production (MWyr) by time, Case 1, GHG50 Scenario.

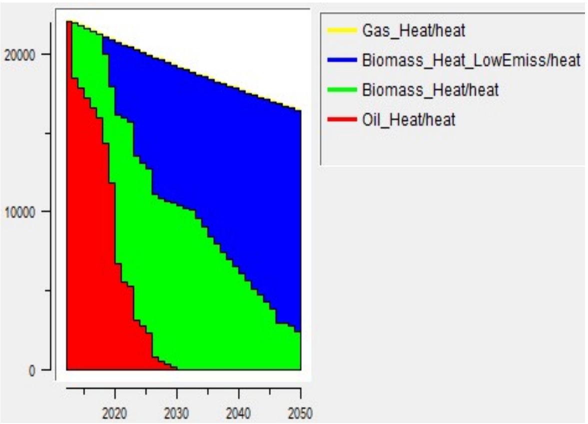


FIG. 9. Heat production (MWyr) by time, Case 1, GHG75 Scenario.

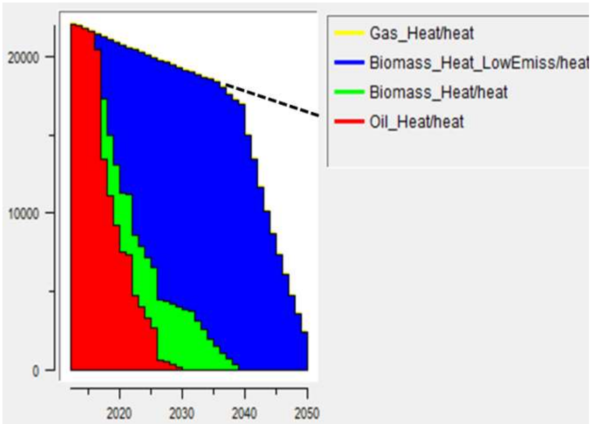


FIG. 10. Heat production (MWyr) by time, Case 1, GHG90 Scenario.

In Figs 11 to 14 the electricity production in Case 2 (with cogeneration, but without any additional costs) is presented for the corresponding GHG emission reduction scenarios. In the Basic scenario system uses, again, the cheapest resource (coal) to satisfy the electricity demand.

It can also be observed that, having dual output (electricity and heat) and one of the lowest CO_2 emission the Gas_PP_new technology is used preponderantly in the GHG90 scenario, when the GHG restrictions are the hardest (see Fig. 14, yellow colour).

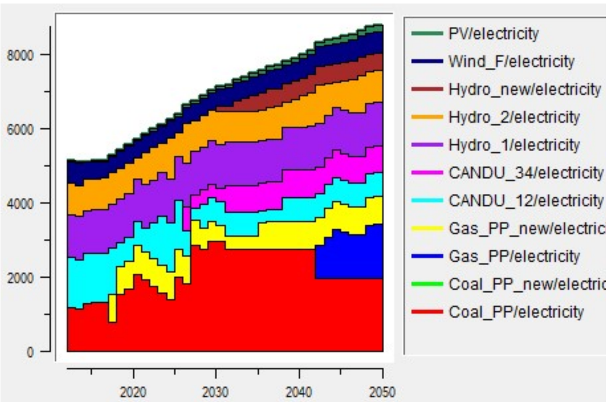


FIG. 11. Electricity production (MWyr) by time, Case 2 (withCog), Basic scenario.

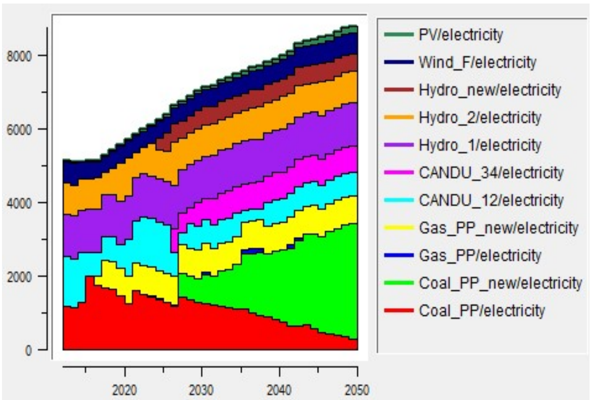


FIG. 12. Electricity production (MWyr) by time, Case 2 (withCog), GHG50 Scenario.

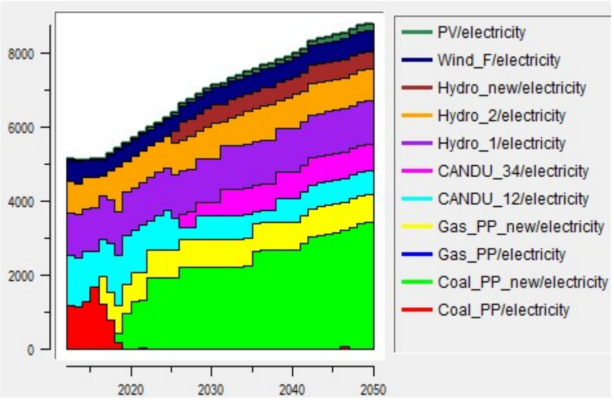


FIG. 13. Electricity production (MWyr) by time, Case 2 (withCog), GHG75 Scenario.

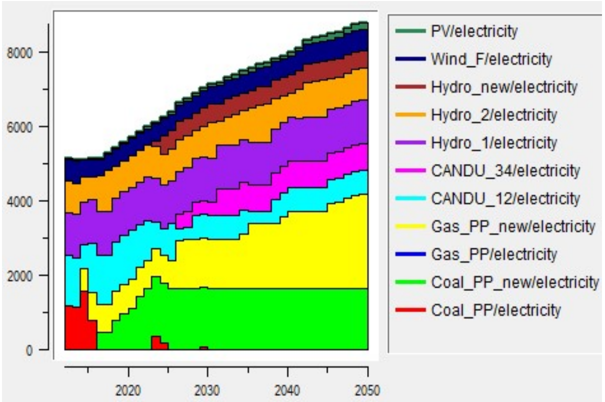


FIG. 14. Electricity production (MWyr) by time, Case 2 (withCog), GHG90 Scenario.

Heat production in the Case 2 is shown in Figs. 15 to 18.

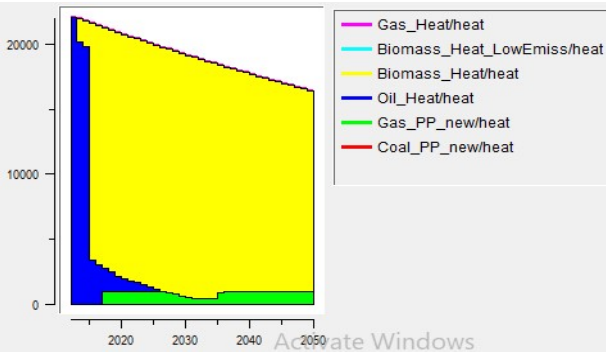


FIG. 15. Heat production (MWyr) by time, Case 2 (withCog), Basic scenario.

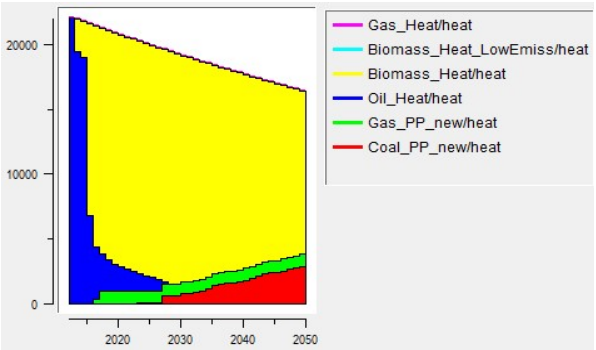


FIG. 16. Heat production (MWyr) by time, Case 2 (withCog), GHG50 Scenario.

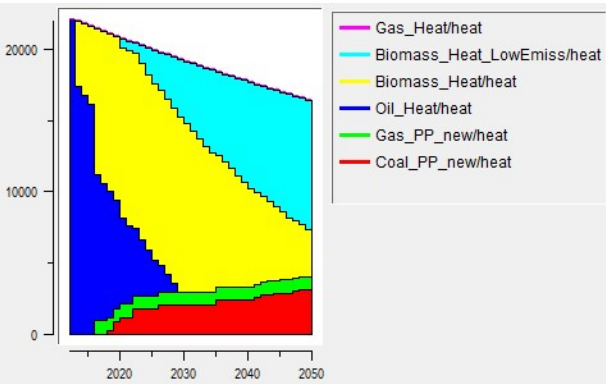


FIG. 17. Heat production (MWyr) by time, Case 2 (withCog), GHG75 scenario.

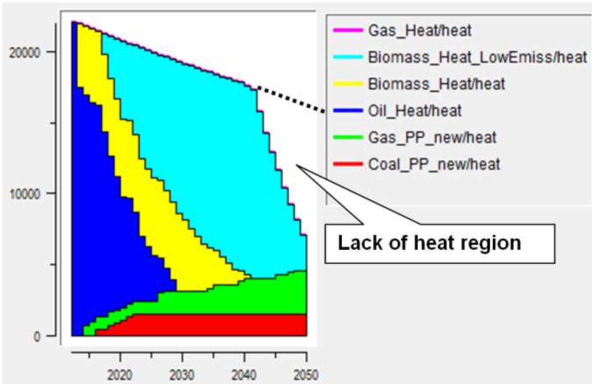
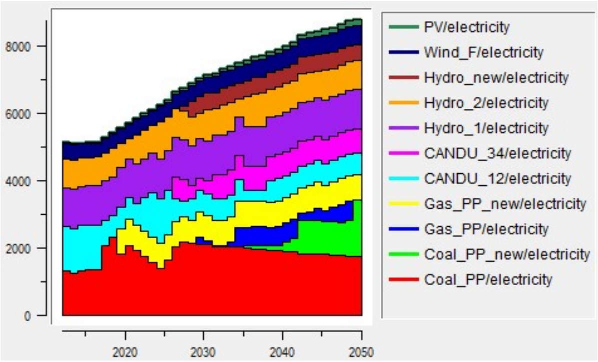


FIG. 18. Heat production (MWyr) by time, Case 2 (withCog), GHG90 Scenario.

This time, the system uses a larger variety of technology to meet the heat demand, including those with dual output (Coal_PP_new and Gas_PP_new). In spite of that, again in the GHG90 scenario the heat demand is still not satisfied for entire period. Now, the lack of heat generation is shifted a few years at right compared to similar scenario in Case 1, i.e. heat resources are exhausted starting with 2040, instead of 2036.

Electricity production in Case 3 (with cogeneration plus 20% increase in the investment cost of technology having cogeneration) is shown in Figs 18 to 21. The main observation is that in scenarios with strong emission constraints (GHG75 and GHG90) there is an increasing use of natural gas than in the Case 2, of course, along with coal with high efficiency and low emissions (see Figs 21 and 22).



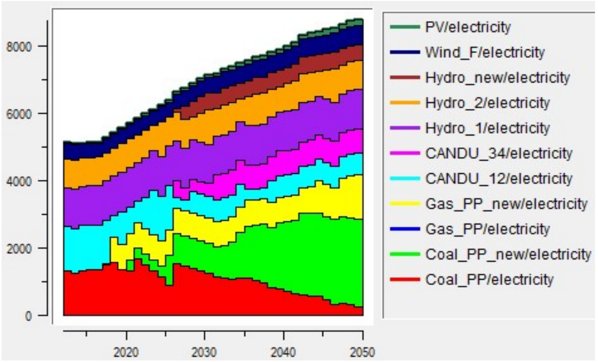
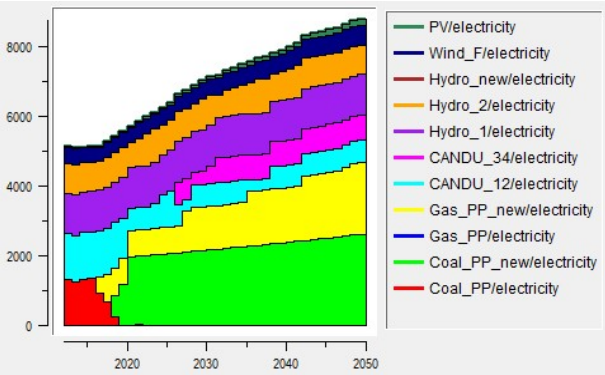


FIG. 19. Electricity production (MWyr) by time, Case 3 (withCog+20%inv.), Basic scenario.

FIG. 20. Electricity production (MWyr) by time, Case 3(withCog+20%inv.), GHG50 Scenario.



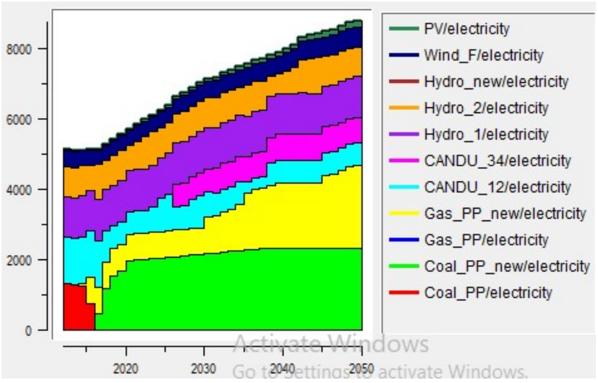


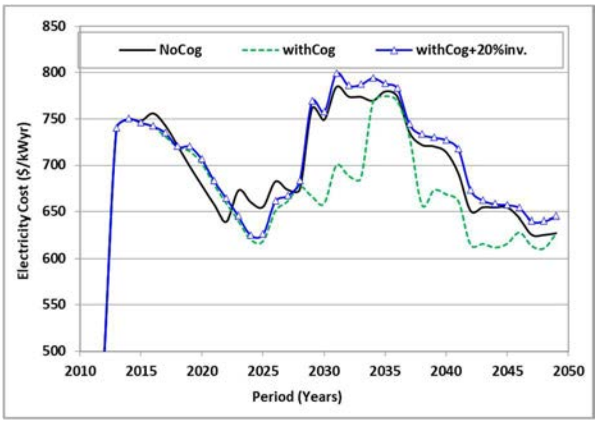
FIG. 21. Electricity production (MWyr) by time, Case 3 (withCog+20%inv.), GHG75 Scenario.

FIG. 22. Electricity production (MWyr) by time, Case 3 (withCog+20%inv.), GHG90 Scenario.

The heat production is similar to that of Case 2, with ascending contributions of biomass in the total heat amount; as a result it has not been represented yet. It should again be mentioned that, as in previous two cases, the heat demand in the GHG90 scenario could not be satisfied. This time, the last sustainable year is 2037, instead of 2040 (Case 2) and 2036 (Case 1). This behaviour of the system reveals clearly that a GHG reduction by 90% compared to 2011 levels (this meaning a decreasing from 70 000 to 7000 ktons CO_2) is not sustainable. At the end of this section, it is concluded that the GHG75% scenario remains the best in terms of sustainability and achieving the largest CO_2 emission reduction.

4. ELECTRICITY AND HEAT PRODUCTION COSTS

The electricity and heat production costs are other criteria envisaged to appreciate the sustainability of an energy development scenario. Figs 23 to 30 present the electricity and heat production costs ($/kWyr) in every scenario of the three cases alluded in Table 1.



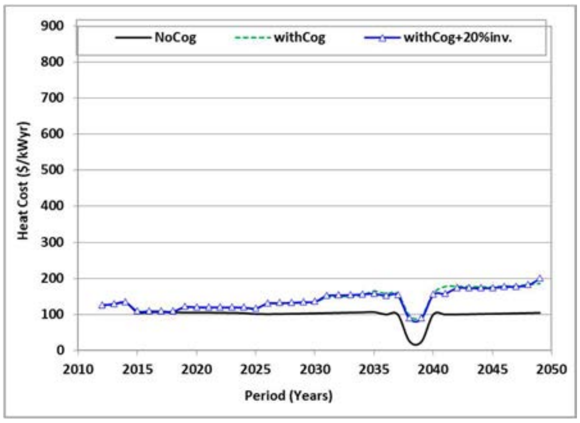


FIG. 23. Electricity cost, Basic Scenario.

FIG. 24. Heat cost, Basic scenario.

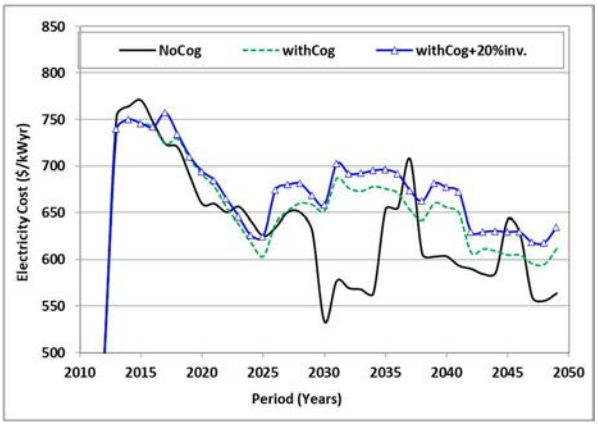


FIG. 25. Electricity cost, GHG50 Scenario.

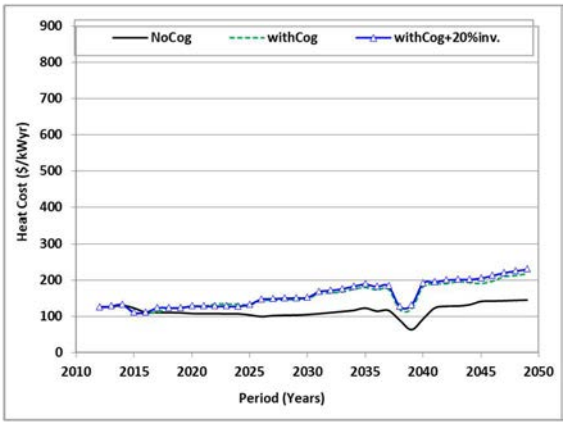


FIG. 26. Heat cost, GHG50 Scenario.

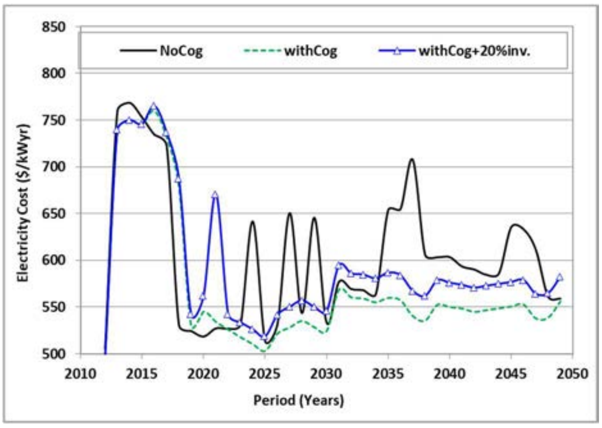


FIG. 27. Electricity cost, GHG75 Scenario.

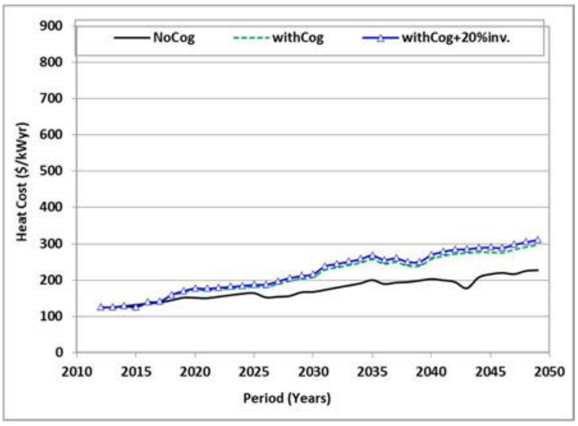


FIG. 28. Heat cost, GHG75 Scenario.

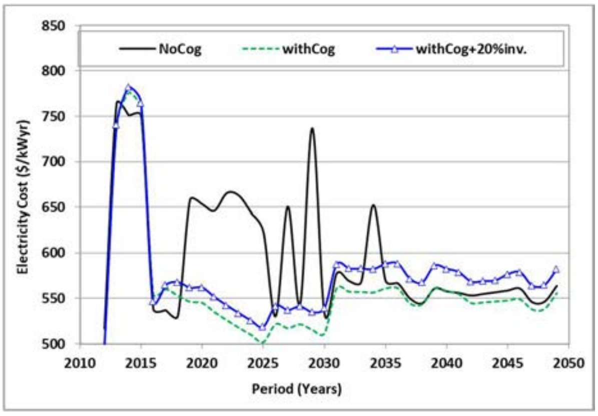


FIG. 29. Electricity cost, GHG90 Scenario.

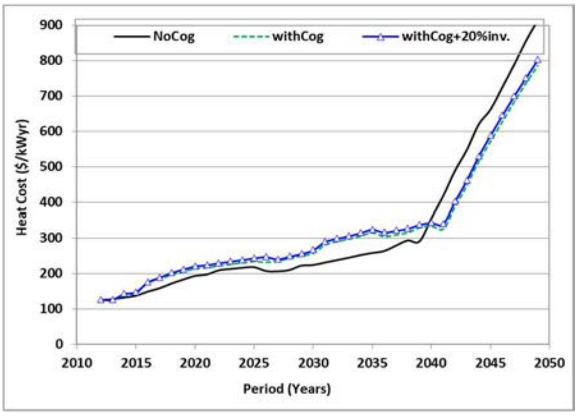


FIG. 30. Heat cost, GHG90 Scenario.

The main observation is that in the frame of a Case (1, 2 or 3) the Basic scenario (with no CO_2 restriction) led to higher electricity production costs than in the situation of scenarios with restrictions (see Figs 23, 25, 27 and 29), especially after 2005. As opposed, the heat cost increases by CO_2 restriction strengthening (see Figs 24, 26, 28 and 30) and becomes not sustainable starting with 2040 when an abrupt rise is revealed (see Fig. 30). On the other side, the comparison case to case shows that cogeneration leads to more cost effective electricity production in scenarios with strong CO_2 emission restrictions (see Figs 27 and 29). Thus, cogeneration can help Romanian energy system to allow for a cleaner electricity production. CO_2 emissions are presented in Fig. 31.

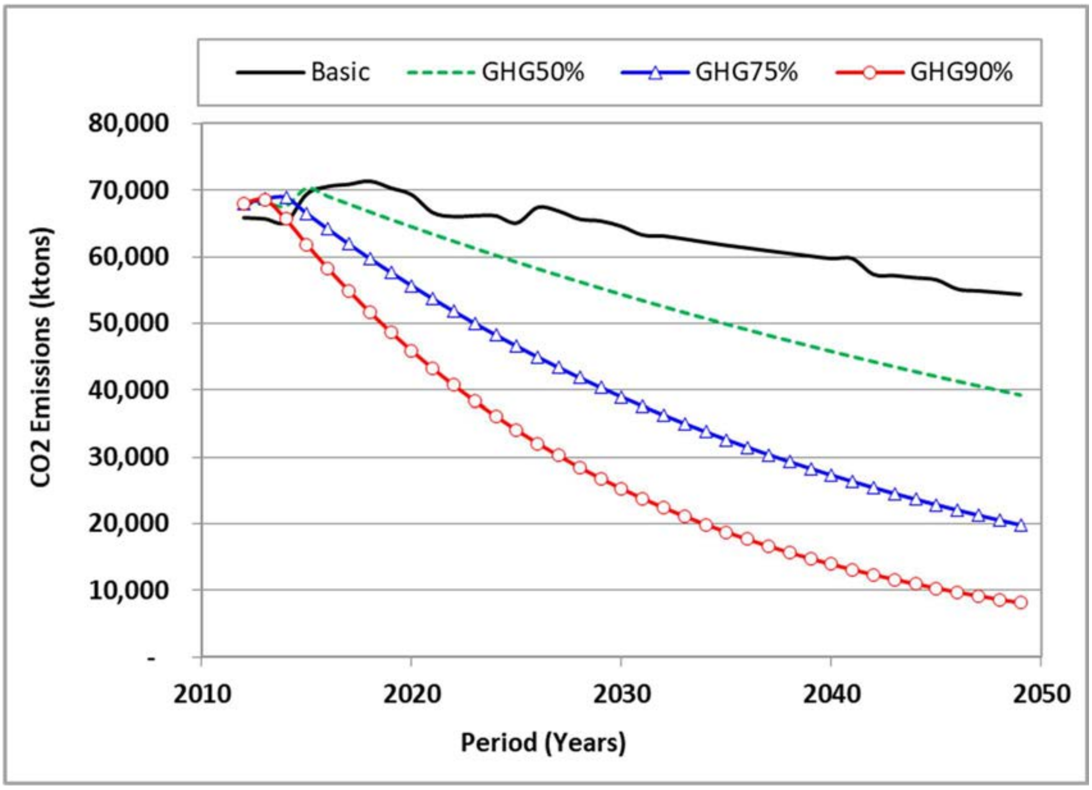


FIG. 31. CO_2 emissions inside of the four scenarios.

5. CONCLUSIONS

The main benefits regarding cogeneration utilization in Romania are:

- The cogeneration can assure more cost effective electricity production in scenarios with strong CO_2 emission restrictions, helping Romania to attain the decreasing CO_2 emission targets;
- Cogeneration is more environmentally friendly by using in a more efficient manner the energy through the burning of fossil fuels;

The main challenges regarding cogeneration in Romania are:

- The actual tendency of decommissioning the existing cogeneration units due to not satisfying the environmental requirements;
- The lack of investments in maintenance of distribution networks of CHDS and weakness quality of services offered to consumers who are tempting to migrate towards individual heating solutions.

The presence of nuclear energy in all scenarios with shares up to 20% of the total electricity production reflects its pillar position in the future Romanian energy system development, this allowing for working together with renewable intermittent energy sources also present in Romanian energy mix.

A maximum sustainable Romanian contribution to energy decarbonization consists of a CO_2 gradual reduction attaining 75% in 2050 from 2011 levels (70 000 ktons/year).

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RENEWABLE ENERGIES IN ALGERIA

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Abstract

Algeria is embarking on a new energy era; it has initiated a sustainable and green energy dynamic based on a strategy focused on the development of inexhaustible resources and the diversification of energy sources. In February 2011, the government adopted a program for the development of renewable energies and energy efficiency. In its experimental and technological intelligence phase, the apparition of new and relevant elements in the energy scene, both nationally and internationally, led to its readjustment in 2015. Since solar energy holds most of the national renewable energy potential, Algeria considers this energy as an opportunity and a lever for economic development. This does not exclude from the program many wind farms projects and the implementation of biomass, geothermal and cogeneration projects.

The updated Renewable Energy Program aims to install a total renewable power of approximately 22 GW by 2030 for the domestic market, with the export option as a strategic objective if the market's situation allows it.

Renewable energies and energy efficiency are at the core of Algeria's energy and economic policies. By 2030, 37% of the installed capacity and 27% of the electricity produced for domestic consumption will be of renewable origin.

1. NATIONAL PROGRAM OF RENEWABLE ENERGIES

Table 1 shows the increase in renewable capacity during a first phase from 2015–2020 and a second phase from 2021–2030, as well as the total installed capacity by the year 2030.

TABLE 1. CONSISTENCE OF THE NATIONAL PROGRAM OF RENEWABLE ENERGIES

	2015–2020	2021–2030	TOTAL
Photovoltaic (MW)	3000	10 575	13 575
Wind (MW)	1010	4000	5010
CSP (MW)	—	2000	2000
Cogeneration (MW)	150	250	400
Biomass (MW)	360	640	1000
Geothermal (MW)	5	10	15
TOTAL (MW)	4525	17 475	22 000

During the second phase 2021–2030, the development of the electrical interconnection between North and South (Adrar), will allow the installation of large renewable energy plants in the regions of South and their integration in the national energy system.

Algeria's strategy in this area aims to develop a real renewable energy industry associated with a training and research program as well as the acquisition of the necessary experience, which will ultimately allow the use of local engineering for all phases of development of these areas. The EnR

Program, for the electricity needs of the national market, will create tens of thousands of direct and indirect jobs.

Electricity production is estimated to reach 90 TWh in 2020 and 170 TWh in 2030. The integration of renewable energy into the energy mix is a major challenge intending to preserve fossil resources, to diversify the electricity production sectors and contribute to sustainable development.

2. RESEARCH AND DEVELOPMENT

Algeria is promoting research to make the renewable energy and energy efficiency programs a real catalyst for the development of a national industry that will value different Algerian potentialities (human, material, scientific, etc.).

Companies and agencies in the energy sector cooperate with research centres attached to the Ministry of Higher Education and Scientific Research, which include CDER and CRTSE.

The lines of research are based on studies that make it possible to analyse the behaviours of equipment in the environment in which they are installed, in order to improve their performance and to facilitate the integration of renewable energy into the electrical system. These networks will have to be managed in a more reactive way, which can be solved thanks to the technologies of Smart Grids.

3. INCENTIVES MEASURES AND TAXES

In order to better meet the priorities of actions set out in the Renewable Energy and Energy Efficiency Program and to encourage initiatives by individuals and businesses, legislative and regulatory changes have been made to respond effectively to the challenges facing renewable energies and energy efficiency.

In addition to the general framework governing the development of investment whose specific regime of the convention can be opened to the promotion of renewable energies, the legal framework in force provides direct and indirect support for renewable energies.

In particular, incentive measures are provided by the Energy Efficiency Law (financial, fiscal and customs benefits) for actions and projects that contribute to improving energy efficiency and the promotion of renewable energies which was established to help finance projects.

The National Fund for Energy Management, Renewable Energies and Cogeneration (FNMEERC), which is supplied annually with 1% oil royalty, was instituted to contribute to the financing of projects.

4. REGULATORY MEASURES

The proactive policies of Algeria in the realization of the program for development of renewable energies and energy efficiency will be made through granting of subsidies to cover additional costs incurred on the national electricity system. In addition, regulatory measures will regulate the State’s contributions and define the conditions and the appropriate control mechanisms to allow for optimal use of the public funds that are allocated to this program.

5. PRESENTATION OF SONELGAZ/SKTM

Sonelgaz is the incumbent operator in the field of supply of electric and gas energies in Algeria. It is organized as a ‘holding company’; together with its subsidiaries, it forms a group called ‘Groupe Sonelgaz’.

SKTM, also known as Sharikat Kahraba wa Takat Moutadjadida, a company producing electricity and developing renewables, is a subsidiary of the Sonelgaz group. Founded in April 2013, the company is in charge of managing and developing the production network of isolated networks in southern Algeria and of the development of renewable energies throughout the national territory. SKTM also deals with the marketing and sale of the energy it produces to distribution network managers.

Key figures being:

- Investments: 306.334 billion Algerian Dinars.
- Installed capacity: 20 963 MW;
    - SPE/SKTM: 15 665 MW;

        - Other producers: 5298 MW.
- Electricity production: 72 395 GWh;
    - SPE/SKTM: 39 452 GWh;
    - Other producers: 32 943 GWh.
- Network length (electricity): 368 024 km;
    - Distribution network: 338 380 km;
    - Transmission network: 29 644 km.
- Network length (gas): 129 289 km;
    - Distribution network: 107 692 km;
    - Transmission network: 21 597 km.
- Number of customers:
    - Electricity: 9 605 685 customers;
    - Gas: 5 628 267 customers.
- Human resources: 91 000 employees.

6. PROJECTS ACHIEVED

6.1. Meteorological measurements

To confirm solar and wind potential previously determined from satellite measurements, ten weather stations were installed:

- Average sunshine duration: 2600 to 3500 hours/year.
- Average energy received 1700 to 2600 kWh/km^2/year.
- Average wind speed: 5 m/s.

6.2. Pilot projects:

- A 1.1 MWp photovoltaic power plant was built in Ghardaia to test different panel technologies; four types of panels were installed in fixed and trackers (mono and polycrystalline amorphous and CdTe). A team of researchers from the CDER (MESRS) monitored and analysed the performance of different types of solar panels in arid and semi-arid environments.
- A 10.2 MW wind farm was also installed in Kabertene in southwestern Algeria.

6.3. 343 MWp project in photovoltaic power plants:

A total capacity of 343 MWp spread over twenty sites with a power ranging from 3–60 MWp, is already installed as part of the deployment of the national renewable energy program. These sites have been operational since 2016.

The renewable production accumulated by July 30, 2018 is on the order of 1000 GWh. The gains are as indicated below:

- Isolated networks of the South:
    - Fuel gain: 27 300 tons;
    - CO_2 emissions avoided: 70 000 tons.
- Northern interconnected networks and Adrar loop:
    - Gain in gas: 170 million tons;
    - CO_2 emissions avoided: 700 000 tons.

7. PROGRAM UNDER DEVELOPMENT

SKTM is entrusted with the production of 150 MW in EPC over the 2019–2021 period, at a rate of 50 MW/year, mainly aimed at hybridizing existing diesel plants in southern Algeria.

Another program is also under development by the Electricity and Gas Regulatory Commission (CREG) in IPP under a power purchase agreement (PPA) for a period of 20–25 years.

Other sectors are involved in the development of clean and sustainable energies such as local communities, water resources, agriculture and Sonatrach.

8. ELECTRONUCLEAR PROSPECTS IN ALGERIA

Increasing demand for electricity is linked to economic and social development.

The introduction of cost competitive energy sources while taking into account environmental issues becomes a necessity.

Nuclear energy perfectly meets these requirements because it relies on an abundant fuel and does not emit greenhouse gases.

Several parameters favour the introduction in Algeria of nuclear power plants, among these:

- The availability of basic nuclear facilities (research).
- The availability of qualified labour, capable of supporting the safe introduction of this technology into the country.
- The availability of substantial reserves of uranium in the Hoggar mines (Sahara).
- The existence of a national regulatory framework.
- Accession to international agreements, conventions and treaties on the non-proliferation of nuclear weapons.

Sonelgaz, the energy operator in Algeria, has introduced nuclear energy in its energy model. In the framework of the development of strategic plans and electricity production, several scenarios of an eventual introduction of nuclear power plants by 2030 were considered.

Sonelgaz' activities are, at this moment, limited to feasibility studies, which are carried out jointly with COMENA and under IAEA supervision:

- Planning.
- Preparation of the operators.
- Watching over specific aspects relating to safety and site studies.
- Monitoring of new technologies.
- Aspects related to the different types of existing contracts.
- Impact studies on the network (they show that 1400 MW units/slices can easily be integrated without disturbances).

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IMPACT OF INTERMITTENT RENEWABLE RESOURCES ON POWER SYSTEM ECONOMICS AND DISPATCHABLE POWER PLANTS OPERATION IN PAKISTAN

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Abstract

Pakistan has framed policies to further the development of intermittent renewable resources (IRR) in the country. Consequently, IRR share is steadily growing in the electric power supply system (EPSS). This research work assesses the impacts of IRR on the EPSS in long term future, more specifically on the operation cycle of dispatchable power plants and system economics. The EPSS is analysed considering different shares of IRR in the system. The analysis shows that the EPSS of Pakistan can accommodate up to 50–60 GW IRR at a future demand level of 149 GW, which corresponds to about an 11% share of IRR in the total electricity generation. Beyond that, the country can face both operational and economic challenges in handling the power supply system.

1. INTRODUCTION

For the last 30–40 years, Pakistan has sustained a significant share (~25%–30%) of clean energy in its EPSS, mainly in the form of hydropower and nuclear energy. In 2006, the government of Pakistan (GOP) devised its first renewable energy policy to expedite IRR development and facilitate investors for this purpose [1]. Consequently, solar i.e., photovoltaic (PV) and wind power started to penetrate the electricity supply market of Pakistan. Currently, the installed capacity of grid connected PV is about 400 MW and that of wind is 938 MW. Similarly, around 556 MW PV and 624 MW wind projects are under development and expected to be completed by 2018–19 [2].

Furthermore, a noticeable capacity of PV is operating off grid or as captive power projects in the country. According to [3], about 100 MW PV panels were imported by Pakistan during 2007–2013 and the current per annum imports are assessed to be around 950 MW [4]. This growth in the demand of PV panels can be attributed to: (a) improved economics of PV generation; (b) prevailing load shedding since 2007–08; (c) distributed generation and net metering allowed by NEPRA in 2014, which facilitate household, commercial and industrial consumers to develop their own PV based power generation facilities [5]; (d) international support and efforts to promote renewable energy generation as an option to slow down climate change. In the future, therefore, further increase in the share of IRR generation can be expected in the EPSS mix of Pakistan.

In this research, Pakistan's power system is analysed in a long term future to assess the impacts of IRR in general and PV addition in particular on the operation of dispatchable power plants (DPPs), and ultimately on system economics. For this purpose, the EPSS is simulated and analysed considering different shares of total renewable resources (RE) in the system.

2. RESEARCH METHODOLOGY

Generally, a high temporal resolution is desired while simulating a power supply system having a significant share of IRR[2] due to uncontrolled frequent variations in their availability. For this research work, several modelling tools, including OSeMoSys (Open Source Energy Modeling System), EnergyPLAN, and HOMER (Hybrid Optimization Model for Electric Renewables) were considered. These frameworks/tools can simulate a demand–supply balance at the desired time resolution (e.g., hour) and are conveniently available[3].

However, these tools were not used for three major reasons. First, the country's major hydropower plants' (HPPs) sites are in cascading positions, therefore release of an upstream reservoir based hydropower plant (ReHPP) affects the generation of downstream HPPs. In these tools, HPPs can be modelled as one or more blocks of power generation systems, operating independently of one another. Second, the country's downstream water requirements are fulfilled through a specific pattern of water storage and release from the reservoirs [6]. In these tools, it was difficult to incorporate such patterns. Third, the tools do not consider dispatchable power plants (i.e., nuclear and thermal) technical/operational limitations (e.g., minimum operation level, ramp rate etc.). Consequently, a simulation tool was developed with hourly temporal resolution to overcome the above mentioned limitations. In a brief form, the simulation approach is presented in Fig. 1, having the following main characteristics.

2.1. Hydropower and IRR generation

Using hourly temporal resolution, the generation of IRR is utilized on a priority basis to serve demand. Next, the simulation process assesses hydropower generation. For this purpose, the daily share of water to be released from the reservoir is assessed using information on the water inflow, current stored water, and IRSA (Indus River System Authority) monthly release patterns for water from the reservoir. The share is then distributed in hours of the day proportionally to the residual demand (i.e., demand after considering utilization of IRR)[4] to generate relatively more power by ReHPP in hours when the gap between demand and IRR generation is relatively high. With this approach, the generation of hydropower (i.e., ReHPP and RRHPP) is simulated and considered for utilization with a priority next to IRR.

2.2. Storage system

In this study, the demand–supply balance is simulated with and without consideration of pumped hydroelectric storage system (PHES). When considered, its capacity depends upon IRR total capacity, as described later in this paper. In each hour, PHES looks for excess generations (generation > demand) due to uncontrolled IRR and RRHPP generations, which is later used in hours of need. During both storage and utilization processes, constraints on the storage size and pump capacity are applied[5]. Similarly, the storage system stored committed as well as excess generation of DPPs. Here, committed generation means generation by DPPs to support the operation of the storage system in specific hours (i.e., during periods of low demand)[6]. Likewise, negligible, but still excess, generation by DPPs can be observed due to limitations of ramp rate (RR) and minimum level of operation.

2.3. Dispatchable power plants

The residual demand is then balanced by DPPs in each hour. For this, constraints/limitations on RR, minimum capacity factor (MCF), and minimum operation level (MOL) are applied. During simulation, RR and MCF are the parameters to prioritize different technologies i.e., the technology having lower value of RR and high value of MCF is preferred over the others. This helped to consider initially

[2] IRR here means wind and PV resources.

[3] There are few frameworks, which could fulfill the requirements. But access to these frameworks is limited e.g., REMix (Renewable Mix), RPM (Resource Planning Model).

[4] The distribution is applied if the daily share (i.e., quantity) of water is less than the water needed to operate HPP of the reservoir at full power.

[5] It is not necessary to store all the excess generation.

[6] DPPs support storage system, only if allow to do so, for specified number of hours. In this study, the number is 5 hours per day.

baseload DPP technology, then load following, and finally peaking ones. Since, for modelling, different unit sizes of a DPP technology are considered (see Table A.1 of the Appendix) the constraint of MCF not only limits the total installed capacity of a technology but also of a specific unit size (i.e., when a unit of large size cannot operate at desired MCF, smaller is opted).

2.4. External grid connection

Finally, import from an external grid system is considered to balance the positive residual demand or to export the excess generation. However, the value of import/export cannot exceed the capacity of the grid connection. The capacity of the external grid connection is described later in this paper.

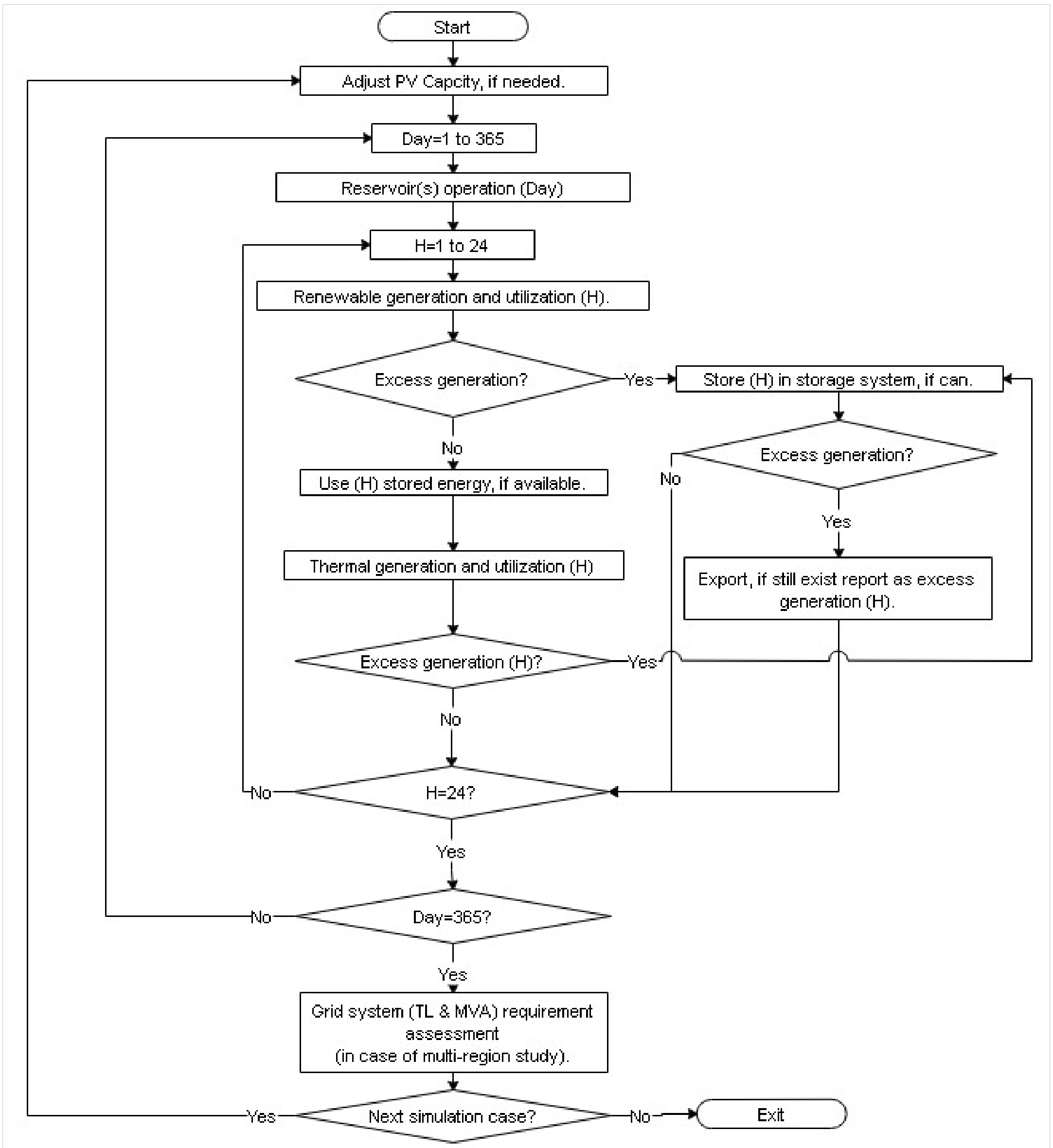

FIG. 1. Simulation approach to assess demand–supply balance.

3. SYSTEM DEMAND

The peak demand of Pakistan electric power system was 27.8 GW with a load factor of 64.8% in 2016–17 [7]. According to Pakistan's National Power System Expansion Plan (PSEP) study, the demand is expected to reach 149.7 GW by 2035 [8]. However, comparison of the forecasted values with recent ones shows conspicuous difference and the values are considerably higher than actual ones for the period 2013–2017. These observations are convincing to expect the 149.7 GW load after 2035 and therefore were considered in this study for the analysis of the system.

Historical data of Pakistan's power system show little variation in the load factor of the system during the last 20–25 years[7] and was in the range of 65% as mentioned earlier. In the long term future, an increase in the load factor can be expected with economic growth, particularly in the social and industrial sectors. However, it is beyond the scope of this research work to incorporate these dynamics and generate a synthetic demand pattern of electricity in the country. In this research work, therefore, the demand pattern of 2011 is used to simulate hourly demand–supply balance of the system [9].

4. PRESENT ELECTRICITY SUPPLY SITUATION

Currently, Pakistan's EPSS installed capacity is around 33.7 GW. The system is mainly based upon gas and oil generation and the installed capacity of the two supply options is 55.7% of the total. Beside other factors, this dependency results in an acute shortage of energy due to the volatility of international oil prices and scarcity of indigenous resources (i.e., oil and gas). This dented the country's economic growth and severely affected its social sector. In the future, therefore, an increase in the shares of coal, nuclear and RE (i.e., hydro and IRR) are expected to make the EPSS mix more balanced, maintaining affordable economics.

5. SUPPLY SYSTEM SCENARIO

5.1. Hydropower

Pakistan's hydropower potential is about 55–60 GW [10]. However, development of this capacity is challenging due to (a) high capital cost of HPP, (b) difficult terrain of the potential sites and (c) seasonal variation in the water availability. In this research, therefore around 50% (~27 GW) of the potential is considered to simulate the system. For the simulation, water inflow data of the country's river system were collected from WAPDA (Water and Power Development Authority) [11][8].

5.2. Wind power

Potential sites of Pakistan's wind resources are mainly located in the south and southwestern parts of the country. However, exploitation of the southwestern potential looks difficult due to lack of infrastructure in the area. It is more than 500 km away from the national grid. In addition, there is little information regarding exploitable potential and wind speed (i.e., measured) of the sites[9]. In this research, therefore, the potential is not considered. The southern sites' exploitable potential is around 11 GW [12]. In this study, 50% of the total potential is considered in the Base_Case and 100% in the subsequent cases for the simulation/analysis. The measured wind speed data of the site are received from Alternative Energy Development Board [13].

5.3. Dispatchable generation

The capacity of DPPs is assessed by simulating demand–supply balance, as mentioned in the methodology section. However, as the GOP has planned 8.8 GW nuclear power by 2030, a maximum of 20 GW (including installed capacity) of the technology is considered as candidate capacity. For thermal generation, candidate technologies included baseload (i.e., coal), load following (i.e., coal, gas) and peaking (gas, oil) power plants. Table A.1 (Appendix) of the paper contains information regarding technical parameters of the DPP technologies, considered for the supply system modelling.

5.4. PV capacity

According to NREL [14], PV based power generation potential in Pakistan is around 11.5 TW, considering only built up and barren/sparsely vegetated land. This capacity is around 400 times the current peak demand of the country. In this research, therefore, no limit was applied on the capacity of the resources. Except Base_Case, the capacity of PV is assessed using following relationship.

$$RE\ share = \frac{Hydro\ (\text{MWh}) + Wind\ (\text{MWh}) + PV(\text{MWh})}{System\ demand\ (\text{MWh})} \tag{1}$$

[7] Load factors of the period 2007–2011 are slightly higher and most probably due to prevailing load shedding during the period.
[8] Data of upper tributaries, which is generally not reported, were obtained through own efforts.
9 The sites were not worked out by World Bank project [15].

$$PV\ (\mathrm{MW}) = \frac{PV(\mathrm{MWh})}{8760 * \mathrm{PV\ capacity\ factor}} \tag{2}$$

Since the capacity of hydropower and wind is decided during modelling, therefore, PV capacity is adjusted to achieve the desired RE share. In Base_Case, the PV capacity is assumed to be 2.4 GW i.e., six times of the current installed capacity. For simulation, hourly solar insolation data are obtained from a database recently developed by the World Bank [15].

5.5. Storage system

The role of the storage system is critical for reliable operation of an EPSS having substantial share of IRR. Currently, pumped hydroelectric storage (PHES) is the most economically viable option to store large amount of energy. In Pakistan, no information exists regarding total potential of PHES. However, a capacity of 13 GW–32 GW was estimated by [16], considering available natural water bodies in the country. In this research work, the system is simulated with and without a storage system. When considered, the PHES capacity is determined using the following general approach in each case:

$$PHES\ capacity = 5\% * PV\ capacity + 5\% * Wind\ capacity \tag{3}$$

5.6. External grid connection

Pakistan imports electricity from Iran through a 100 MW line and the line capacity is expected to be increased to 1000 MW [17]. Similarly, a Central Asia–South Asia (CASA) transmission line of 1000 MW capacity is also under development [18]. In this study, therefore an external grid connection of 2000 MW is assumed for import/export with fixed energy price of US 8¢/kWh [19]. However, the priority of using imports is the least one as mentioned in the methodology section. The reason is obviously the uncertainty in a flexible availability of these lines for imports. In Table 1, a summary of the supply system is presented.

6. FINDINGS

6.1. Supply system mix

In general, increase of IRR in a supply system reduces operation margin for baseload power plants. In the case of Pakistan, the phenomenon is more obvious during summer due to high hydro and PV generation, as shown in Fig. 2[10]. The figure shows hourly demand–supply balance of RE_30% case (i.e., 11 GW wind and 114.1 GW PV) during the month of May[11]. In this high IRR case, planned shutdown of most of the baseload DPPs (i.e., nuclear, coal, and CC gas) occurred during summer[12], still the installed capacity requirements of the baseload DPPs significantly reduced. Relative to Base_Case (i.e., 119 GW), the available space for baseload DPPs reduced almost 50% in RE_30% case. For further clarification, the impact of IRR on the generation mix of DPPs can be assessed from annual energy balance of the cases, presented in Fig. 3.

The balances show that decrease in the baseload share is relatively low in RE_15%. In this case, the ReHPP helped to minimize the impact of IRR variable generation. However, in the later cases, the capacity of IRR is significantly higher than the total ReHPP and the system therefore opts for more flexible DPP technologies.

6.2. Dispatchable plants operation

Commonly, electricity demand varies and addition of IRR can further contribute to the variations from the DPP perspective. Following the tendency, analysis shows significant increases in the demand–supply gap, to be taken care of by DPPs, with the increase of IRR. In the Base_Case, the maximum gap is about 26.3 GW, which reached to around 29 in RE_20% and 35.6 GW in RE_30% case as shown in

[10] 3%–4% transmission losses were assumed. In addition, PHES losses further contribute in the total losses when operate, therefore, the supplied energy is slightly more than demand.
[11] The excess generations indicate storage system load and system thermal losses.
[12] It is done by simulation process for an efficient operation.

Fig. 4. The figure shows initially a relatively low growth in the gap but then exponential with IRR additions in the system. Consequently, DPPs with low capacity factors were opted to balance the demand and, therefore, overall capacity factor of the DPPs was reduced as can be seen in the figure.

TABLE 1. SUPPLY SYSTEM RESOURCES IN DIFFERENT SIMULATION CASES

SUPPLY RESOURCE	CAPACITY (GW)	
	Base_Case	Rest of the Cases (i.e., RE_15%, RE_20%, RE_25%, RE_30%)
Hydro	26.9	26.9
Wind	5.5	11.0
PV	2.4	Determined to meet RE share
Nuclear	20 (Maximum)	
Thermal	Determined through simulation	
Storage system*	0.05 x PV Capacity + 0.05 x Wind Capacity	

*Applicable only when storage is considered.

Note: (i) Renewable Energy (RE) indicated by case name included hydro generation. (ii) Actual percentage of RE is slightly high than mentioned in name e.g., in case RE_20%, it is around 22%, due variation in hydro generation and losses. (iii) The Base_Case RE share is around 12%.

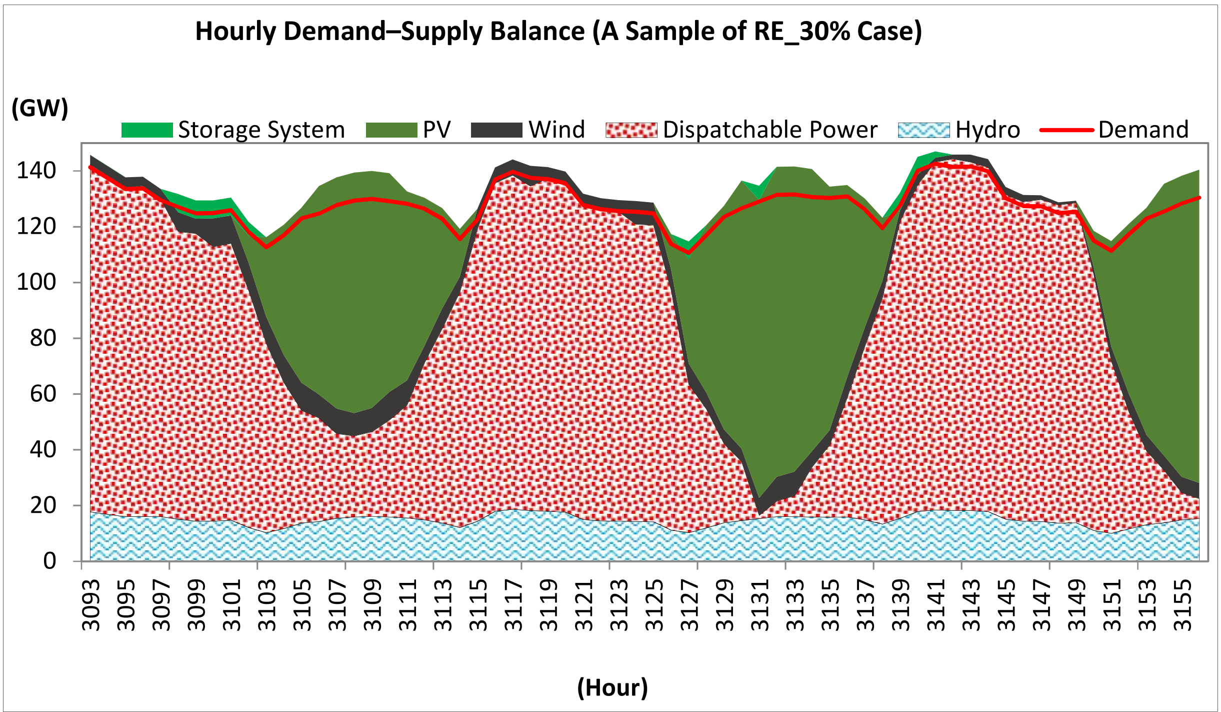

FIG. 2. Hourly demand–supply balance (sample of RE_30%).

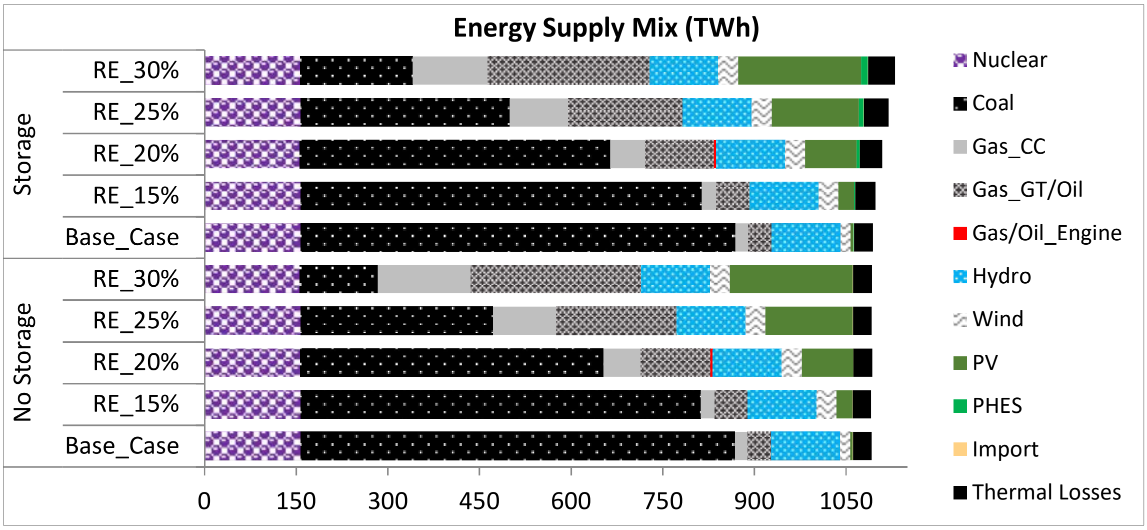

FIG. 3. Electricity supply mix in different cases.

The variations in the demand supply gap to be handled through DPPs across the year results in increase of the plants shutdowns. In general, the shutdowns affect system economics due to requirement of (a) thermal energy for restart and (b) increase in the maintenance cost of DPPs. In this study, an exponential increase in the shutdowns was observed with increase in IRR share as shown in Fig. 5. The figure also shows that the presence of a storage system reduces the shutdown, but this results in a slight increase in the chance of cold shutdowns. Understandably, the stored energy of a storage system increases the chances of DPP unavailability for a few hours and achieving a cold shutdown state instead of hot or warm shutdown.

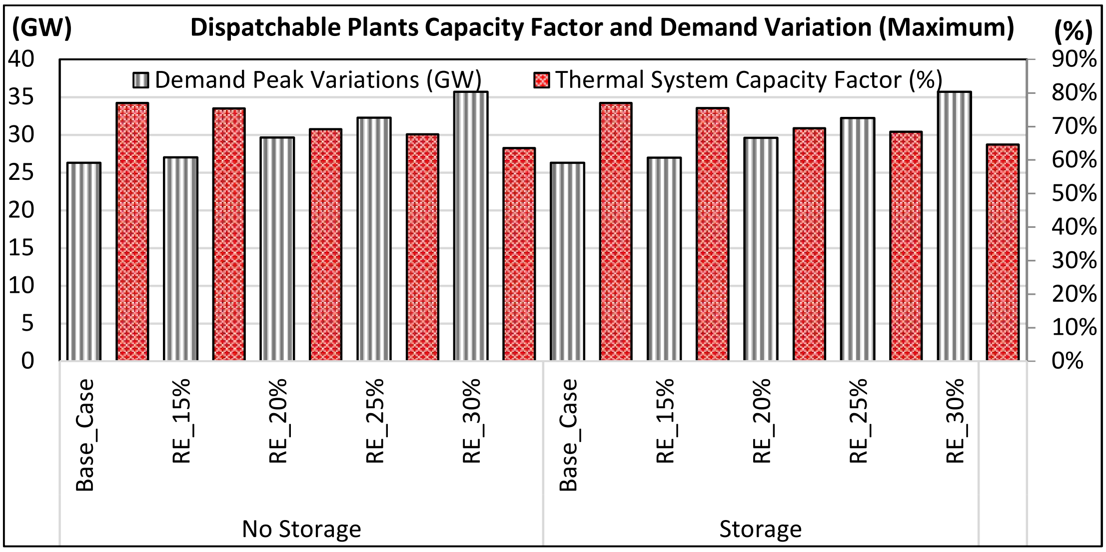

FIG. 4. Dispatchable plants capacity factor and max. value of demand–supply gap.

6.3. System cost

The information used for levelized cost (LC) assessment is given in Table A.2 (Appendix). While calculating the LC, the additional cost of DPPs due to the energy requirement for restart is incorporated. However, increase in the maintenance cost due to shutdown is not included in the cost. This also does not include financial costs, insurance, etc., and capital cost of existing capacity. Furthermore, the cost is based upon demand rather than generation to incorporate the impact of thermal losses, imports and exports, using the following approach:

$$LC = \frac{\sum_{t=1}^{N} ACC_t + \sum_{t=1}^{N} VC_t + \sum_{t=1}^{N} FC_t + \sum_{t=1}^{N} IC_t - \sum_{t=1}^{N} ER_t}{Total\ electric\ energy\ demand} \quad (4)$$

where ACC is annualized capital cost, VC is annual variable cost, FC is annual fixed cost, IC is import cost, and ER is export revenue. Based upon the approach and considering an interest rate of 10%, the LC of different cases is presented in Fig. 6, which shows a noticeable rise with increase in IRR. This increase in the LC can be attribute to (a) relatively high levelized cost of IRR, (b) increase of load following and peaking DPPs share, which were permitted to operate at low capacity factors to meet the demand as mentioned in the methodology and (c) frequent shutdowns of the DPPs. In the case of a storage system, additional capacity and high thermal losses further increase the system LC.

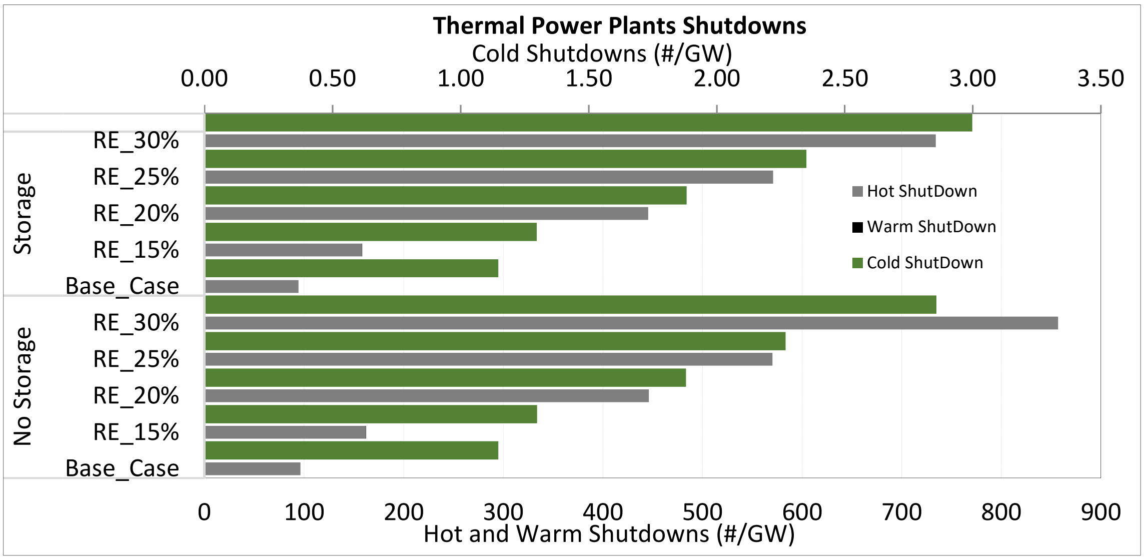

FIG. 5. Shutdowns of dispatchable plants in different cases.

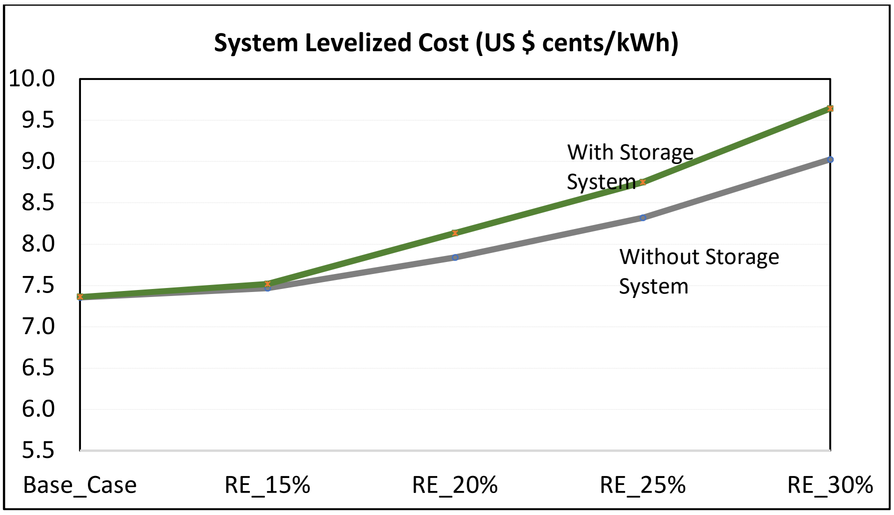

FIG. 6. Supply system levelized cost.

7. CONCLUSION

Based upon the analysis, the case RE_20% looks achievable for Pakistan without major operational and economic challenges. In this case, IRR (i.e., wind and PV) contribution is around 11% of the demand (i.e., 1030 TWh). The case corresponds to 11 GW wind, 48 GW PV, and around 3 GW PHES (i.e., when considered for a reliable operation). The capacity can be operated with around 97 GW baseload DPPs, which is around 11 times Pakistan's planned nuclear capacity by 2030. This means that the planned nuclear power plant can conveniently operate, having the case IRR, in the EPSS. Further increase of the IRR can raise both operational as well as economic issues for the EPSS of Pakistan.

Importantly, the analysis considered current technoeconomic data of power generation technologies. However, following the current trend, a relative improvement of IRR economics can increase the manageable capacity of the resources in Pakistan's EPSS.

Note: The future plan is to incorporate the probabilistic nature of IRR, using equivalent load curve, which was not done due to required extensive data of resources.

Appendix

TABLE A.1. CANDIDATE TECHNOLOGIES OF DISPATCHABLE POWER GENERATION [20]

TECHNOLOGY		Nuclear	Coal (Imp)	Coal (local)	Gas_CC	Gas_GT/ Oil	Oil/Gas Engine	
UNIT SIZE (MW)		1000	600	300, 150	600, 300	250, 150	150, 50	
RAMP RATE (% of Capacity)		0.1	0.5	0.5	0.7	0.7	0.7	
MIN. OPERATION LEVEL (%)		0.8	0.6	0.6	0.3	0.2, 0.1	0.1	
MIN. CAP. FACTOR (%)		0.8	0.8	0.8	0.75	0.2, 0.1	0.05, 0.02	
AVAILABILITY FACTOR (%)		0.9	0.85	0.85	0.9	0.95	0.95	
EFFICIENCY (%) AT MIN. OPERATION		0.3	0.33	0.3, 0.28	0.5	0.32, 0.35	0.3, 0.28	
MAX. EFFICIENCY (%) AT RATED POWER		0.33	0.38	0.35, 0.33	0.60, 0.58	0.37, 35	0.35, 0.33	
SHUTDOWNS PERIOD CRITERIA (Hours)	HOT	8	8	4	4	4	4	4
	WARM	16	16	16	16	16	16	16
	COLD	50	50	50	50	50	50	50
REQUIRED RESTART TIME (Hour)	HOT	1	3	3	1	0	0	0
	WARM	10	4	4	3	0	1	1
	COLD	32	8	8	5	1	2	2
RESTART ENERGY COST (MWh/MW)	HOT	5	3	3	0.2	0.02	0.02	0.02
	WARM	8	5	5	1.5	0.05	0.05	0.05
	COLD	16.7	10	10	4	1	1	1

TABLE A.2. TECHNOECONOMIC DATA OF ELECTRICITY GENERATION TECHNOLOGIES [21,22,23]

TECHNOLOGY	CAPITAL ($/kW)	FUEL ($/Tonne)	VARIABLE O&M ($/MWh)	FIXED O&M ($/MW/yr)	LIFE (Year)
Nuclear	2973	**	2.30	60000	60
Coal (Imp.)	1483	120.1	1.16	25892	35
Coal (local)	1485	103.17	1.16	25892.	35
Gas (CC)	908.5	700	2.91	17631	35
GT_Gas/Oil	795	708.7	3.41	20215	35
Wind	1930	—	11.42	—	25
PV	1067	—	16.83	—	25
Hydro (ReHPP)	4000	—	1.04375	18.74	60
Hydro (RORHPP)	2200	—	1.04375	18.74	60

**For Nuclear, 7$/MWh fuel cost is taken from literature, mentioned in the Ref.

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SESSION II

INTEGRATION OF RENEWABLES WITH NUCLEAR INSTALLATIONS

OPPORTUNITIES AND CHALLENGES FOR NUCLEAR–RENEWABLE HYBRID ENERGY SYSTEMS

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Abstract

Tightly coupled nuclear–renewable hybrid energy systems (N–R HESs) are systems that link subsystems to generate dispatchable electricity and produce at least one industrial product from two or more energy resources. Because N–R HESs are designed to produce different products based on the value of those products in markets, their optimal designs and operations can be complex. This paper summarizes some key conclusions from a set of economic analyses of N–R HESs. Each N–R HES use case analysed includes a nuclear reactor, a thermal power cycle to convert nuclear energy into electricity, either a wind or photovoltaic solar subsystem producing electricity, and an industrial process producing an energy or an industrial product. The analyses focused on identifying the optimal configuration and hours of operations for each N–R HES within ranges of hypothetical future electricity price profiles and industrial product prices. Four important insights are drawn from the results of those analyses.

1. INTRODUCTION AND MOTIVATION

Energy generation and use across all sectors of the economy is rapidly evolving. The market share of wind and solar photovoltaics (PV) in the electricity sector is growing. At the same time, the surge in natural gas production in the United States has driven down the cost of power generation using natural gas turbines and combined gas turbine/steam cycle power plants that have the flexibility to provide operating reserves as well as energy to the grid. That flexibility supports higher penetrations of wind and PV. Commercial and residential buildings are becoming more energy efficient and now require less energy to provide the same level of comfort. Advances in efficiency of appliances and electronics have also limited the increase in energy consumption in the residential and commercial sectors. The transportation sector is both becoming more efficient and more technologically diverse. The industrial sector is finding ways to improve energy efficiency including utilizing combined heat and power and process intensification measures that improve process heating rates and reaction conversions [1]. These trends — coupled with a renewed focus on energy resiliency and security — are motivating investment and utilization strategies for innovative energy generation and delivery assets.

Tightly coupled nuclear–renewable hybrid energy systems (N–R HESs) are a technology opportunity that can generate dispatchable electricity while shifting uncommitted thermal or electrical energy to an energy intensive industrial process that uses heat, steam, and/or electricity to produce fuels, chemicals, minerals, or another commodity. In this paper, as elsewhere, N–R HES are defined as individual facilities which take two or more energy resources as inputs and produce two or more products, with at least one being an energy commodity such as electricity or a transportation fuel [2]. Fig. 1 depicts a conceptual tightly coupled N–R HES.

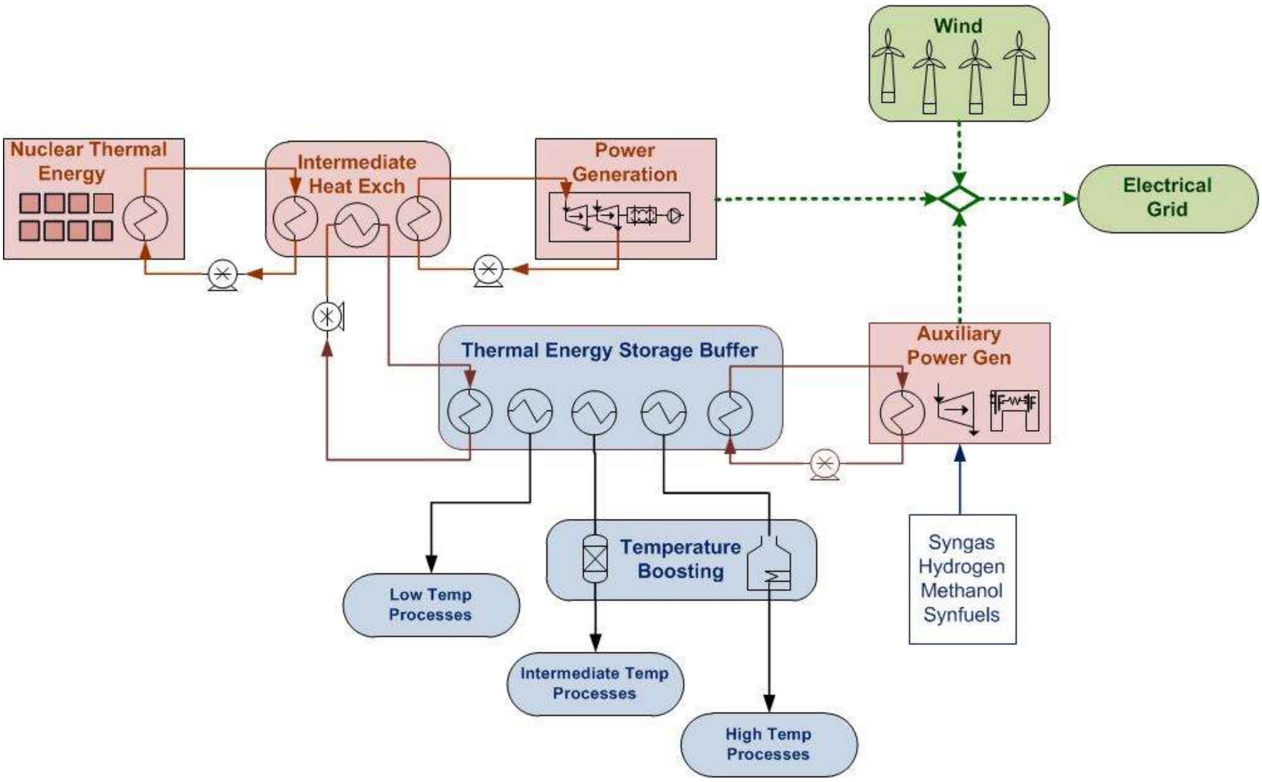

FIG. 1. Schematic of a light water nuclear–renewable hybrid system utilizing wind energy, coupled with generalized industrial processes classified by operational temperature [2].

N–R HESs have been proposed as opportunities that provide a number of potential economic and societal benefits [3]:

(a) Dispatchable, flexible, zero pollutant, and very low carbon electricity generation that supports the grid's needs for energy, capacity, and ancillary services. Because the energy dispatch between electricity production and the industrial process can be controlled, N–R HESs can maximize electricity production when the net demand for electricity is high, thus supporting grid reliability especially during extreme events including ones that limit natural gas availability for electricity generation or periods when variable generation is unusually low. When electricity prices are low, N–R HESs can increase energy use for the industrial process to maximize plant revenues.

(b) Reduced sulphur oxide, nitrogen oxide, particulate, and carbon dioxide emissions and potentially reduced energy costs in the industrial sector when providing process heat instead of combusting coal or natural gas to provide the same service.

(c) Providing ancillary grid services including synchronous electromechanical (real) inertia to support the grid, frequency regulation, and voltage and reactive power support. The N–R HES can provide these services by rapidly ramping up or down electricity to amenable industrial subsystems to compensate for grid perturbations.

(d) Alleviation of the impacts of electricity price suppression at high penetration of low marginal cost generation (e.g., nuclear and renewables) because they provide a floor for energy prices by diverting an energy source from electricity to the industrial process.

2. ANALYSIS OBJECTIVES

This paper summarizes results and draws conclusions from a series of economic analyses of N–R HESs. The overall objective of the analyses was to quantify the economic potential of some specific N–R HES use cases and configurations, compare those results to uncoupled alternatives that provide the same services, and identify when the N–R HES both meets the required hurdle rate and has the potential to be more profitable than the alternatives. Economic potentials are calculated as the net present value (NPV) of the N–R HESs expenses and incomes. Key expenses include the capital investment and operating costs, including those related to feedstocks, labour, and maintenance. Income includes revenue from selling the industrial product, electrical energy, and the value of providing capacity and ancillary services to the grid. Electromechanical inertia [4] or other grid services that are not commonly priced were not included because an economic value could not be assigned to them. Only revenue from selling the industrial product was considered. Hence, additional revenues such as potentially marketable credits for industrial products under renewable identification numbers (RINs) were not included [5].

In some cases, the uncoupled alternatives emit carbon dioxide and results were calculated both without and with a cost of carbon levied on those emissions.

The economic analyses test the following key hypotheses:

- The N–R HES configurations meet a hurdle rate that can be considered a minimum return for investors and that the N–R HES configurations are more profitable than alternatives composed of the same subsystems and uncoupled configurations.
- N–R HESs can be more profitable than uncoupled alternatives because they can generate electricity at times when its price is high and an industrial product at times when the price of electricity is low.
- N–R HESs can support the electricity grid's resource adequacy requirements when needed while maximizing income by producing a higher value industrial product while other grid resources are sufficient, providing market structures support that opportunity.

3. SYSTEMS ANALYSED

The conclusions reported in this paper are based on results from analyses of four different N–R HES use cases reported elsewhere. The four different N–R HES use cases that were analysed are illustrated in Fig. 2. All four N–R HESs analyzed include four potential subsystems: (1) a light water small modular nuclear reactor generating heat; (2) the balance of plant that converts that heat into electricity; (3) a variable renewable generator (wind or PV); and (4) an industrial energy process that produces an energy product or a commodity. Additionally, a short description of each configuration is provided in following paragraphs.

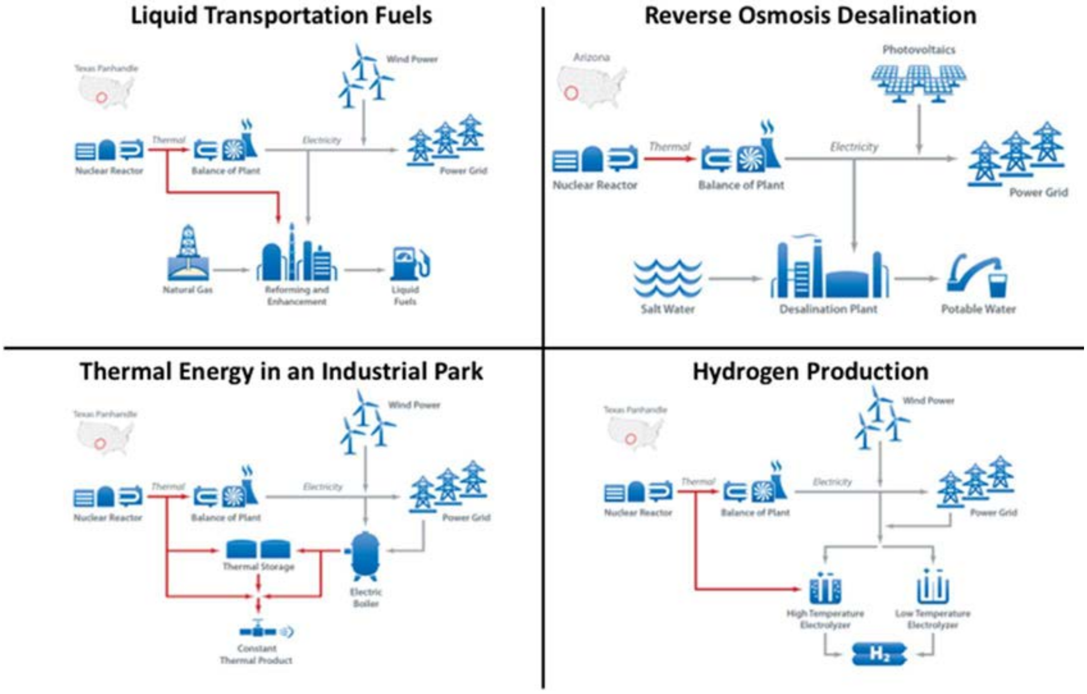

FIG. 2. Graphical depictions of the four N–R HESs that were analysed [6,8,9].

The liquid transportation fuel N–R HES use case includes a subsystem that converts natural gas to a liquid fuel the methanol to gasoline process that involves methanol and dimethyl ether (DME) as process intermediates. The analysis assumes that the liquid fuel can be sold on the market at the same price as gasoline. The synthetic fuel production subsystem has a high capital cost and requires both heat and electricity hence the process has both thermal coupling between the nuclear reactor and the industrial process in addition to electrical coupling that can provide either nuclear generated electricity or wind generated electricity to the industrial process as needed. The project did not consider any market offtake of methanol or DME, which could reduce the equipment required and hence the capital cost of the industrial process. Site specific parameters within the analysis are based on a Texas location because Texas has natural gas and wind resources as well as liquid fuel infrastructure [6].

The desalination N–R HES use case includes a reverse osmosis (RO) desalination unit which requires only electricity as the industrial process. Hence, this N–R HES only has electrical coupling. Site specific parameters are based on Arizona data because Arizona has a saline aquifer that can provide water to the RO unit, a growing demand for potable water, and abundant solar resources. An initial report presents the methodology, assumptions, results, and conclusions of the analysis of these first two N–R HESs (liquid transportation fuel and desalination) [6]. It should be noted that RO desalination is based on modular units so capital costs scale nearly linearly with production rate.

The thermal energy N–R HES use case is slightly different than the two described above. Instead of producing an industrial product, it generates a thermal product (either steam or heat transfer fluid) that can be provided to one or more customers. To produce the thermal product at a constant rate, two variants are considered: thermal storage and an electric boiler. The thermal product would not be produced from nuclear generated electricity due to thermal to electric to thermal energy conversion inefficiencies. Rather, it could be produced from electricity from either the N–R HES's wind subsystem or purchased from the grid depending upon the availability and cost of that electricity when the heat is needed. This N–R HES is situated in Texas because the industrial sector in Texas is large and has a large demand for heat [7]. A second report summarizes the methodology, assumptions, results, and conclusions of the analysis of the thermal energy N–R HES [8].

The hydrogen N–R HES use case involves two variations for the industrial process subsystem. In the first, the industrial process is a high temperature electrolyser (HTE) that utilizes both heat and electricity to generate hydrogen, requiring both thermal and electrical coupling. In the second, the industrial process is a low temperature electrolyser (LTE) that requires only electrical coupling but has a lower efficiency. The analysis was performed on each variant individually. In both variants, the electricity used could be nuclear generated, wind generated, or from the grid. Another report summarizes the hydrogen N–R HES analyses [9].

The published reports describe the analysis of each N–R HES and communicate the results and conclusions from those analyses. This paper reports general conclusions drawn from all four analyses.

The four use cases and their associated configurations that are analysed range over the spectrum of types of N–R HESs. That spectrum ranges from N–R HESs that have only electrical coupling as well as those that have both electrical and thermal coupling. It also includes N–R HESs with industrial processes that have high capital costs and those that have very low capital costs. It also includes N–R HESs that only produce energy as well as those that can purchase electricity when at a low price.

4. ANALYSIS METHODOLOGY

The overall objective of the N–R HES analysis was to identify the subsystem sizes and operational decisions (i.e., the internal dispatch strategy) that are most profitable under a variety of electricity and industrial product prices and compare those to other options that provide the same service. For this purpose, profitability is defined as the NPV of the investment — a higher NPV means increased profitability. Given an interest in achieving more generally applicable conclusions, only the potential for greenfield (all new) plants was considered. Specific opportunities are recognized, including reconfigurations of existing nuclear power plants, could result in conflicting conclusions that are appropriate for those specific opportunities but may not be more generally applicable.

The results reported here were generated using National Renewable Energy Laboratory's (NREL's) REopt tool. REopt is an energy planning platform that offers concurrent, multiple technology integration and optimization capabilities. Formulated as a mixed integer linear program, REopt identifies optimal subsystem sizes and dispatch strategies for the selected technologies. The model accounts for subsystem costs (capital, fixed, and variable), fuel costs, financial parameters (discount rate, inflation, utility electricity price escalation rates, and incentives), utility prices, and other variables that contribute to a technoeconomic analysis of the proposed system. REopt also has the capability to optimize a system for objectives other than those used in this analysis, such as minimum fuel consumption or minimum GHG emissions [10,11]. For this analysis, REopt was extended to incorporate reduced order models of these industrial processes and associated operational constraints. REopt was then applied to determine the optimal subsystem sizes and corresponding dispatch strategies (i.e., the optimal product mix during each hour of the year that would maximize the net present value of each N–R HES given the capital, feedstock, and other operating costs and the product selling prices. Maximum sizes of all subsystems were constrained in each N–R HES to the same value because the purpose of the analysis was to understand the potential of coupled subsystems with full flexibility. The assumption was made that the presence of each N–R HES does not impact market prices (i.e., it does not reduce the price of electricity or the industrial product by flooding that market).

Capital and operating costs and efficiencies used in REopt are based on published estimates and, due to the limitations of the optimization methodology, scaling is linear (i.e., as the ratio between capacity and capital cost is held constant, the subsystems are not scaled exponentially). That limitation is unlikely to impact most of the sensitivities because in most of the instances when the subsystems are included in the optimal configuration those subsystems are at the maximum size (which is also the size at which the ratio was set). Table 1 reports the values used within the optimization and the sources of those values. The assumption was made that the N–R HES would begin operations in 2035 so the values are projected costs and performance in 2035 in 2013 U.S. dollars. The nuclear reactor is based on light water small modular reactor (LW–SMR) technology. Using subjective judgment, the assumption was made that this technology could potentially be commercialized and several built before 2035 following completion of reactor design certification, development of steam line combined technology and operating permits, equipment manufacturing supply chain development, and construction and operating experience. That experience is necessary to meet the 'n^{th} of a kind' cost estimate used in this analysis. Other reactor technologies are under development and may prove to be more economic than LW–SMRs and future analysis using those technologies may be valuable. Capital costs reflect the total cost for the subsystem — they include indirect costs such as foundations and buildings, control systems, and utility connections.

A key input is the electricity markets and performance. Three types of electricity products were included in the analyses:

(1) Hourly electrical energy revenue (dollars per megawatt hour [$/MWh]);
(2) Hourly ancillary service revenue from contingency reserves, regulation, and flexibility reserves (dollars per megawatt [$/MW]);
(3) Annual capacity payments (dollars per kilowatt year [$/kWyr]).

Future electrical energy prices and ancillary service prices were projected using the 2036 generation mix in the National Renewable Portfolio Standard (RPS) scenario in a published set of standard scenarios (2036 was used because only even number years are available) [18]. Areas representative of Northern California, the Public Service Company of Colorado district, and Washington were used to create a mix of generators. That scenario and those locations were chosen because it resulted in an analysis with a high penetration of variable renewable generation (21% of annual generation from wind and 20% from PV) thus requiring flexibility be provided by other generators and lead to high electricity price volatility. Those conditions are expected increase the economic attractiveness of N–R HESs. In that scenario, natural gas combined cycle (NGCC) units generate 26% of the national annual electrical energy produced; hydropower generates 26%; traditional nuclear power generates 6%; and natural gas combustion turbines generate the remaining 1%. The generation mix for each state analysed (Texas and Arizona) was entered into the PLEXOS production cost model to estimate the annual electrical energy production and hourly electrical energy and ancillary service price profiles that would be paid to the provider [6]. To avoid site dependent price volatility, transmission constraints were not included in the PLEXOS analyses. Fig. 3 shows the price duration curves used in the analyses of the liquid transportation fuel, thermal energy, and hydrogen transportation N–R HESs [9]. The price duration curve used in the reverse osmosis desalination N–R HES is available in the report discussing that analysis [6]. Sensitivities were performed to analyse impacts of electricity prices and their volatility. For each sensitivity, a multiplier was randomly generated and the product of that multiplier and each hourly electricity energy price within the profile used as the electricity energy price for that hour.

Electrical energy purchase prices are estimated as the hourly cost plus $15/MWh. The $15/MWh adder is intended to cover costs associated with the transmission and delivery of electrical energy that regional transmission organizations or independent system operators normally incur but are not included in the locational marginal price estimates (e.g., capacity, reserves, and administration). The $15/MWh adder is based on costs reported by the PJM Interconnection [17].

A capacity payment was included because it is a commonly used economic incentive to provide resource adequacy and set it at $50/kWyr based on observed values in restructured markets over the last decade [6]. To receive capacity payments, the N–R HES has to provide electrical power to the grid for the 50 highest load hours during the year based on recent history of hours when available supply was limited [8]. Sensitivities with capacity payments of $100/kWyr and $150/kWyr are performed to help understand the potential of N–R HESs to support the grid's resource adequacy requirements.

The optimization is based on the NPV of the cash flows for the 25 year project financial life for each N–R HES using the calculation method recommended by Short [19]. Table 2 reports key financial parameters for that calculation. The weighted average cost of capital (WACC) in this analysis is 10% reflecting a debt percentage of 0% and a cost of equity of 10%; however, that WACC can be met with various debt/equity ratios with different discount rates. The analysis did not include state or federal policies with the exception of those that impacted the generation mix.

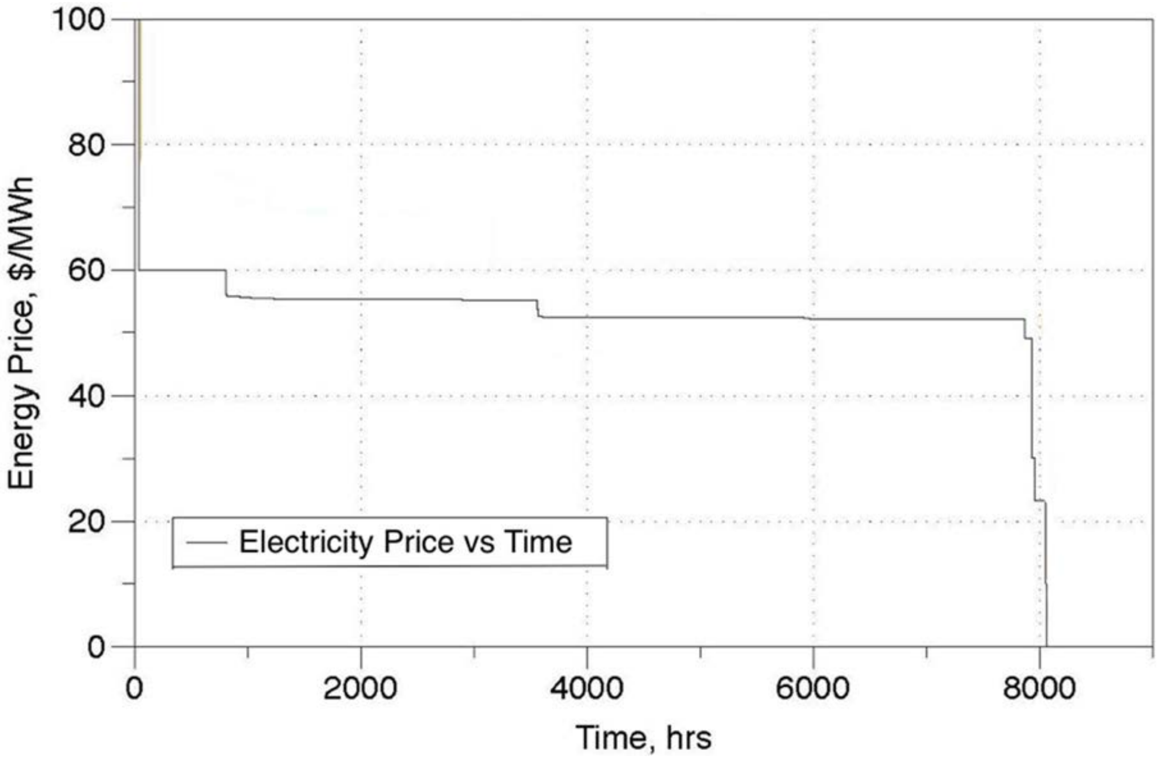

FIG. 3. Price duration curves for electricity energy prices in the Texas location over all hours of the year sorted from highest price to lowest. The price is $0/MWh for 704 hours in the year [6].

TABLE 1. SUBSYSTEM CAPITAL AND OPERATING COSTS AND REFERENCES

SUBSYSTEM	OVERNIGHT CAPITAL COST	FIXED O&M COST	ELECTRICITY REQUIREMENT	THERMAL ENERGY REQUIREMENT
Nuclear reactor [12]	$3716/kW_e$	$95/kW_eyr$	N/A	N/A
Thermal power cycle [14]	$1305/kW_e$	—	N/A	N/A
Wind turbines	$1689/kW_e$ [14]	$46.75/kW_eyr$ [13]	N/A	N/A
Solar PV plant	$1094/kW_e$ [14]	$8/(kW_eyr)$ [15]	N/A	N/A
Liquid fuel production [16]	$12 810/(kg/hr)	$1537/(kg/hr-yr)	Negligible	9140 Btu/gal gasoline[13]
RO desalination plant [17]	$32 894/(kg/s)	$4841/(kg/s-yr)	1125 kg water/kWh electricity	N/A
Electric boiler [8]	$81/kW_e$	N/A	N/A	1 kWh electricity input/kWh heat product
Electric thermal storage unit [8]	$25/kWh_t$ = $125/kW	N/A	N/A	1 kWh electricity input/kWh heat product
Thermal storage unit [8]	$15/kWh_t$	N/A	N/A	1 kWh heat input/ kWh heat product
High Temperature Electrolysis (HTE) [9]	$662/kW_e$	$58.69/kW_eyr$	35.1 kWhe/kg H_2	11.15 $kWh_t/kg\ H_2$
Low Temperature Electrolysis (LTE) – higher capital cost [9]	$616/kW_e$	$42.73/kW_eyr$	50.2 $kWh_e/kg\ H_2$	N/A
Low Temperature Electrolysis (LTE) – lower capital cost [9]	$154/kW_e$	$42.73/kW_eyr$	55.2 $kWh_e/kg\ H_2$	N/A

kW_e: kilowatt electric
O&M: operations and maintenance

5. DISCUSSION AND CONCLUSIONS

Results of full analyses and results of all the N–R HES use cases shown in Fig. 2 are published in individual reports (see [6,8,9]). This section synthesizes overall conclusions and general lessons all of the separate analyses.

The first key conclusion is that the primary driver for whether a subsystem is included in the optimal configuration is whether it would be profitable independently. Under our analytical method and most of our assumptions (economic optimization over a full year; dynamic operations can sufficiently follow economic signals, capital intensive subsystems), inclusion of each subsystem is not dependent upon whether other subsystems are also present. For example, the variable electricity generation subsystem is generally included if it has an NPV greater than zero and is not included if its NPV is negative.

[13] 171 300 Btu (HHV) natural gas/gal liquid fuel is required as a feedstock for the process in addition to the thermal energy requirement.

TABLE 2. KEY FINANCIAL PARAMETERS

START OF OPERATIONS (year)	2035
ANALYSIS PERIOD (years)	25
TAX RATE	35%
COST OF EQUITY	10%
DEBT PERCENTAGE	0.00%
DISCOUNT RATE (nominal)	10%
INFLATION RATE (electricity/water/gasoline/natural gas)	3.0%

Fig. 4 supports this conclusion by showing the optimal configurations for ≈2000 combinations of gasoline price and electricity cost multiplier for the Texas liquid fuel N–R HES configuration shown on the upper left of Fig. 1. Gasoline wholesale prices are varied between \$0.00/gal and \$3.00/gal on the x-axis and the electricity price multiplier that is described in Section 3 is varied from 0.1 to 2.0 on the y-axis. Gasoline prices and electricity price multipliers were independently, randomly sampled from a uniform distribution across the above ranges. The resulting figure shows the profitable configurations.

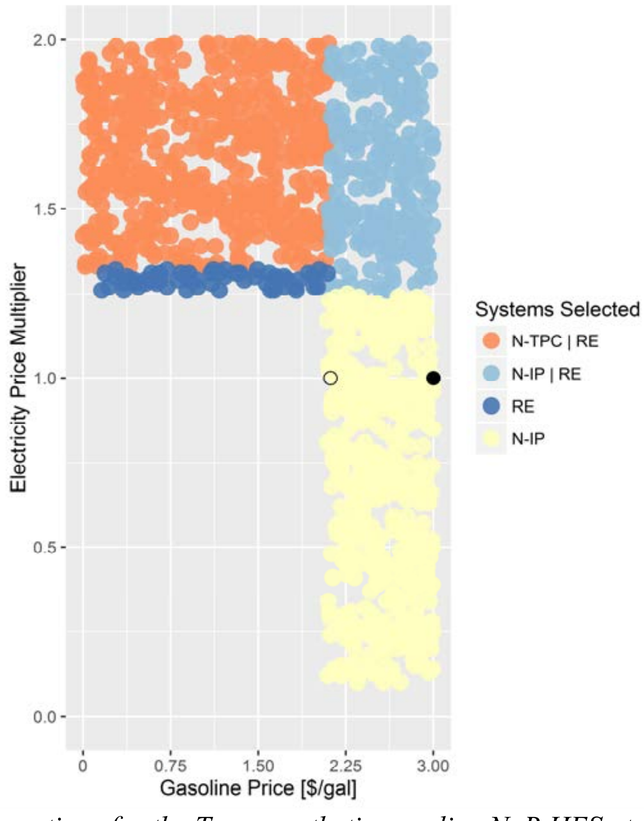

FIG. 4. Optimal configurations for the Texas synthetic gasoline N–R HES at various gasoline prices and electricity price multipliers [6]: N-TPC: Nuclear reactor and thermal power cycle; N-IP: Nuclear reactor and industrial process; RE: Renewable electricity (wind) generation; Solid black dot at electricity price multiplier of 1.0 and \$3.00/gal gasoline price: reference case liquid fuel price projection; reference case electricity price vector;Open black dot: minimum gasoline selling price for a liquid fuel plant using natural gas heating as described on page126 in Ruth, et al [6]; reference case electricity price vector.

Given the configuration and supporting assumptions, the electricity price multiplier must be greater than 1.25 to profitably generate electricity and the gasoline price must be greater than \$2.09/gal to profitably produce liquid fuel. If the electricity price multiplier is less than 1.25 and the price of gasoline is less than \$2.09/gal, no configurations are profitable (i.e., have a positive NPV) so no dots appear in that area in Fig. 4.

— If the electricity price multiplier is between 1.25 and 1.3 and the price of gasoline is less than \$2.09/gal (as shown in the dark blue dots), a wind plant has a positive NPV, but the nuclear reactor is not profitable with either a thermal power cycle or the synthetic gasoline process.
— If the electricity price multiplier is greater than 1.3 and the price of gasoline is less than \$2.09/gal (as shown in the orange coloured dots), both a wind plant and a nuclear reactor–thermal power cycle combination are profitable. However, since the profitability threshold for both technologies operating together (1.3 price multiplier) is horizontal there appears to be no financial benefit to having both electricity generation technologies collocated and operated together.
— If the electricity price multiplier is less than 1.25 and the wholesale selling price of the liquid fuel is greater than \$2.09/gal (as shown in the yellow dots), the nuclear reactor–liquid fuel process is profitable, but neither of the electricity generation subsystems are profitable.
— If the electricity price multiplier is greater than 1.25 and the wholesale selling price of the liquid fuel is greater than \$2.09/gal (as shown in the light blue dots), the nuclear reactor–liquid fuel process is profitable based on the value of the produced fuel alone. The wind generation subsystem is also profitable and is included in the optimal configuration.

Similar examples are published for each N–R HES use case:

One key caveat to this first conclusion is that grid interconnection costs are assumed to be negligible. If having a single interconnection for both renewably generated power and nuclear generated power to the grid is less costly than independent interconnections, then there would be a synergy that makes a configuration with both technologies more profitable than configurations where they are independent. Other factors such as inertia and resilience requirements may also provide additional value for configurations with both forms of electricity generation, but those factors are outside the scope of the analysis.

The second key conclusion is that high capital cost equipment is almost always optimally operated the maximum number of hours possible in a year. Because most industrial processes have a high capital cost, industrial processes are usually optimally operated as many hours as possible. Fig. 5 is from the same result set as Fig. 4. The image on the right shows that, when the gasoline price is over \$2.09/gal, the synthetic gasoline plant is present, and it optimally produces the same amount of liquid fuel no matter what the electricity price is. Hence, the economic optimum is to operate the liquid fuel subsystem at its maximum capacity that uses all the energy produced by the nuclear reactor (i.e., the thermal power cycle is not necessary). The image on the left indicates that electricity is generated when the electricity price multiplier is greater than 1.25. However, in the region with the orange only wind generated electricity is sold. Electricity generated using energy from the nuclear reactor is only sold at an electricity price multiplier greater than 1.3 and low gasoline price less than \$2.25/gal.

This conclusion indicates that electrical pricing is insufficient for optimal N–R configurations to sell electricity when its prices are high and sell an industrial product during the remainder of the year even with high penetrations of renewables resulting in large electricity price swings (as in this analysis) and doubling those price swings by using an electricity price multiplier of 2.0. In this use case, a capacity payment of \$50/kWyr is insufficient for the full N–R HES to produce electricity during hours necessary to receive that payment because the opportunity cost of not producing the liquid fuel during those hours is too high.

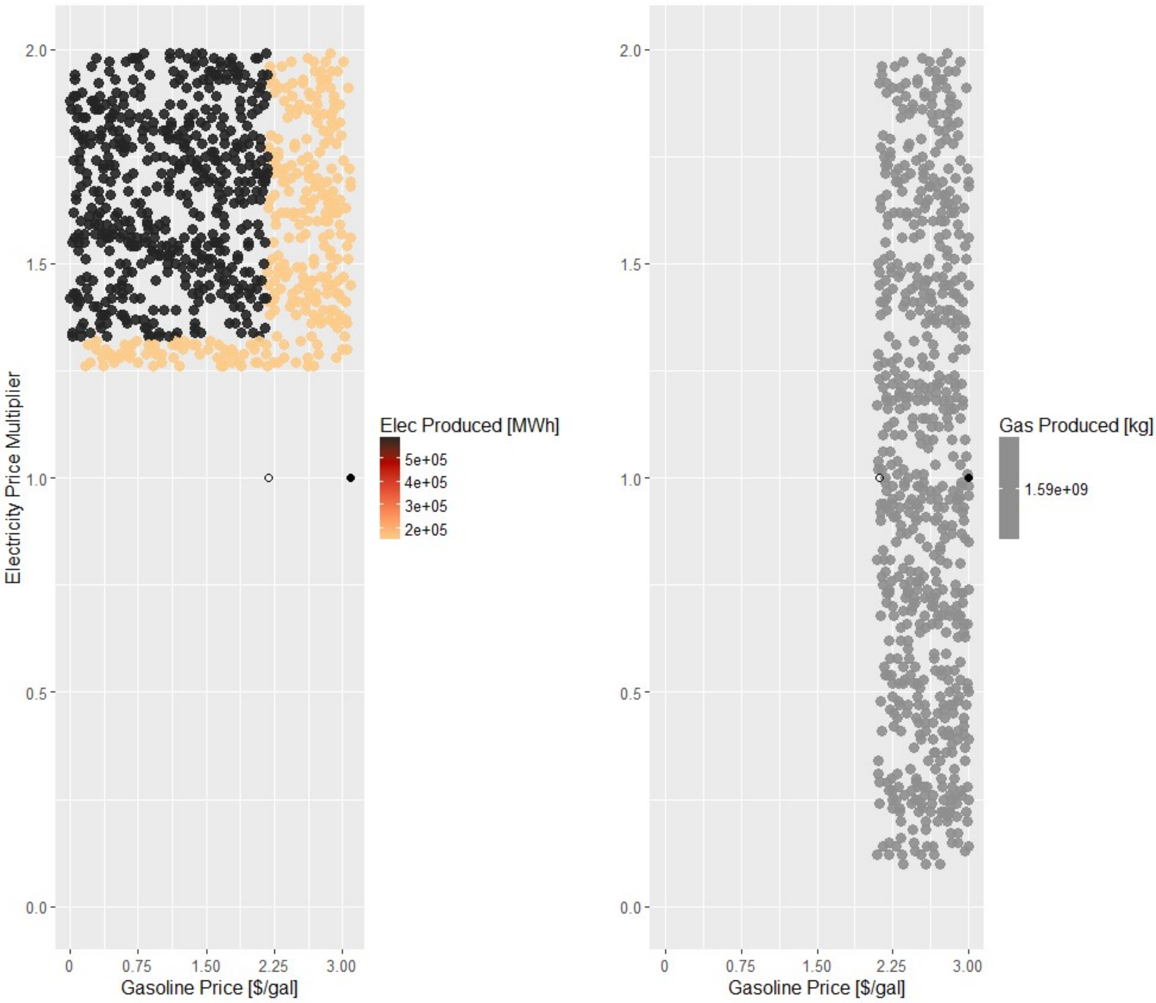

FIG. 5. Optimal annual product generation at various gasoline prices and electricity price multipliers for the Texas synthetic gasoline N–R HES [6]: Electricity is on the left with greater generation at the darker color. Synthetic gasoline is on the right; Electricity pricing based on AEO reference case and $50/kWyr capacity payments.

A key caveat to this conclusion is that capacity payments are sometimes sufficient to incentivize the industrial process to be turned down or off for a small number of hours annually (50 hours/yr in this analysis) to enable the N–R HES to receive both the capacity payment and high energy price during those hours. Fig. 6 shows the electricity production (left) and water production (right) of the optimal configurations and operational strategies for the Arizona desalination N–R HES depicted in the upper right of Fig. 2. The dark blue dots shown when water prices are above $3.40/1000 gal and the electricity price multiplier is below 1.40 indicate that the optimal operation is for the nuclear reactor and thermal power cycle to produce electricity that is used desalinate water during all hours of the year. The white dots in the range when the water price is between $1.18/1000 gal and $3.40/1000 gal indicate that the optimal operation is to use nuclear generated electricity to desalinate water during all but the 50 hours/year necessary to sell electricity to receive the capacity payment. The medium blue and light blue dots are at an electricity price multiplier in conditions where the PV system is included in the optimal configuration. Like the range with the white dots, the light blue dots at water prices the N–R HES optimally sells nuclear generated electricity to supplement PV generated electricity during the capacity payment hours. Not desalinating water to receive the capacity payment reduces the overall production of desalinated water from 400 000 acre feet to 398 000 acre feet but increases income from both electrical energy sales and capacity payment enough to overcome the opportunity cost of not producing those 2000 acre feet of water.

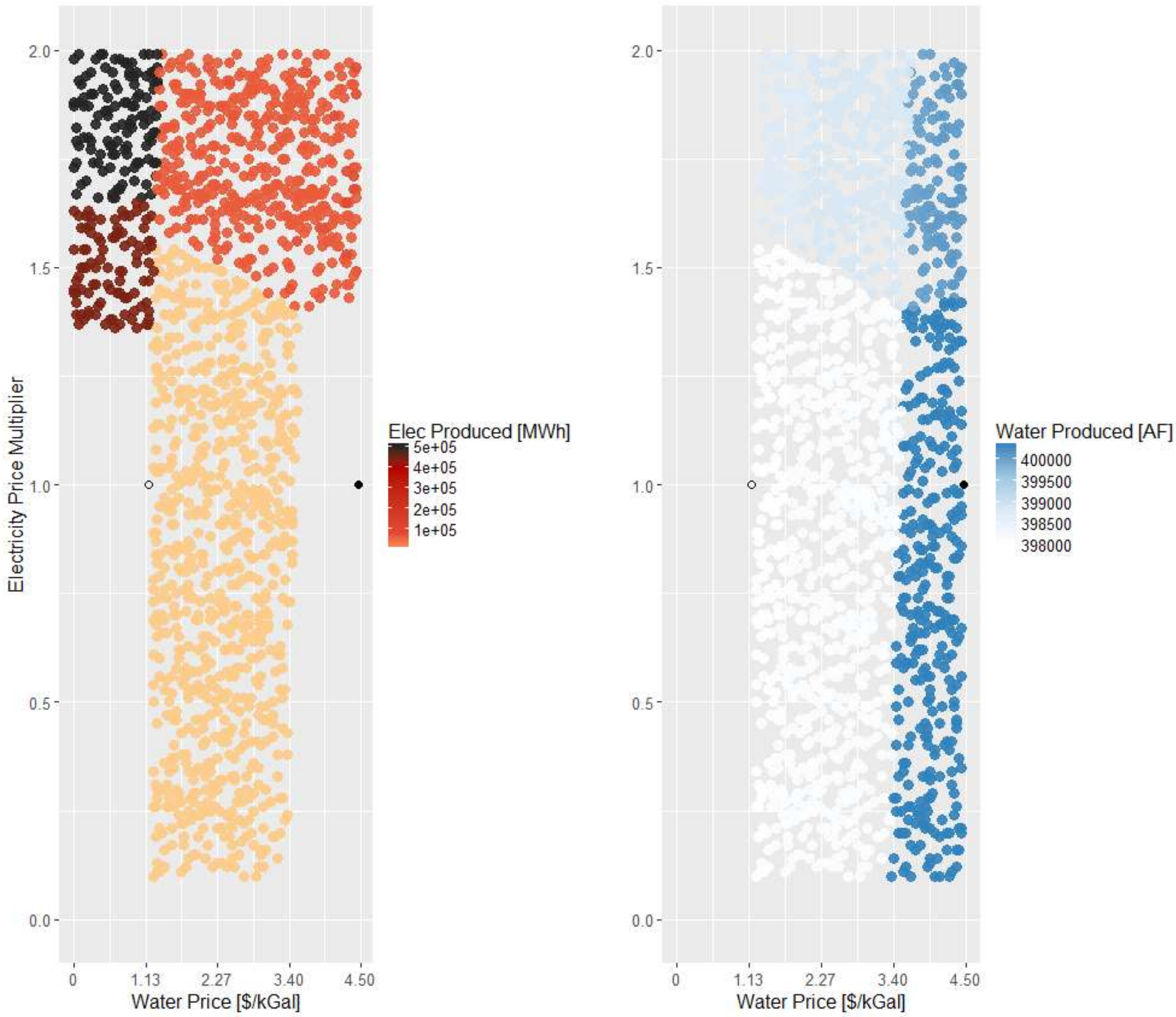

FIG. 6. Optimal annual product generation at various water prices and electricity price multipliers for Arizona desalination N–R HES [6]: Electricity is on the left with greater generation at the darker colour. Synthetic gasoline is on the right; Electricity pricing based on AEO reference case and $50/kWyr capacity payments.

The third key conclusion is that N–R HESs with lower capital cost industrial processes are more likely to utilize their flexibility to switch between electricity and the industrial product more often than their higher capital cost configurations and that this flexibility increases the instances of profitable situations. The reason is that the cost of capital sitting idle while producing electricity instead of the industrial product is not as high. Fig. 7 compares the optimal configurations of an LTE hydrogen N–R HES with a higher capital cost higher efficiency LTE (left) and a lower capital cost lower efficiency LTE (right).[14] The different colour dots in the triangles in each image indicate that, at electricity price multipliers greater than 1.4 and hydrogen prices around $3.85/kg, LTE subsystems with the lower capital and efficiency are included in the optimal configuration whereas those with higher capital costs and efficiencies are not included. The white dots in Fig. 8 that can be found within the red triangle indicate that analysis region has a higher hydrogen production with low cost LTE parameters but that, with the parameters in that analysis region, the N–R HES is only producing hydrogen during about 20% of the time. Nuclear energy is dispatched to produce the highest value product during each hour in that analysis region; however, that type of dispatch was uncommon within the rest of the analysis because the capital cost of most industrial subsystems was too high for them to be built without running them most hours of the year.

[14] Table 1 reports capital cost and efficiency estimates (reported as electricity and thermal energy requirements). Additional details are in the detailed report [9].

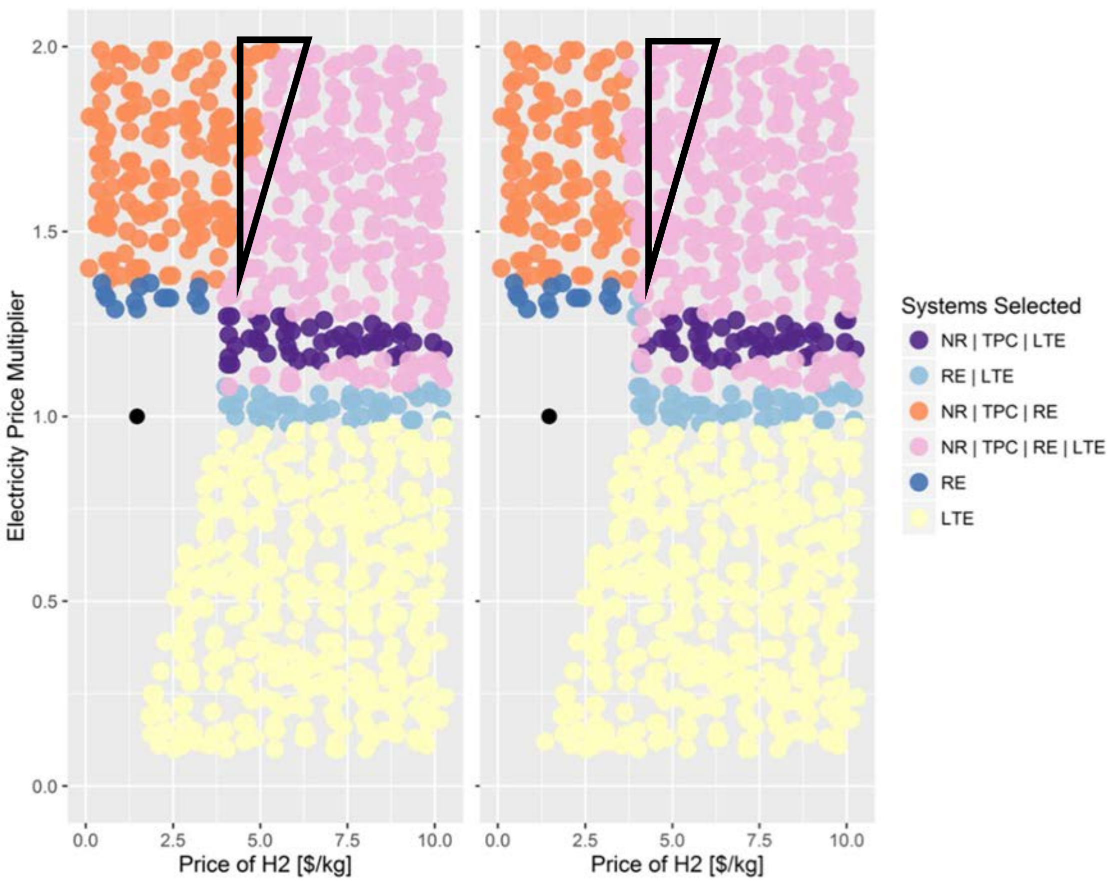

FIG. 7. Optimal configurations for the LTE N–R HES at various hydrogen prices and electricity price multipliers with two different electrolyser prices and efficiencies [9]. Triangles highlight conditions that result in different optimal configurations: Projected high cost electrolyser parameters (left); low cost electrolyser parameters (right); $50/kWyr capacity payments; LTE: low temperature electrolysis subsystem; NR: nuclear reactor; RE: renewable electricity generation (wind power plant); TPC: thermal power cycle.

The fourth key conclusion is that nuclear reactors may be competitive selling thermal energy if a thermal energy market exists and they can access that market. The primary competition for meeting thermal energy demands in the U.S. is natural gas. Fig. 9 plots the levelized cost of producing steam from both a light water reactor based on pressurized water reactor technology and from a natural gas boiler at various natural gas prices.

Levelized costs of steam from LWRs are shown in the horizontal lines. They are calculated from the levelized cost of producing electricity from the LWRs by backing out the cost of steam. Calculations were made using a HYSYS process and thermodynamic model [20]. The model is based on a 7 stage Rankine power system with high pressure steam (750 psia, 560 F) taken before the first turbine. If only lower pressure steam is required, it could be extracted from several locations throughout the power cycle so that electricity can be generated as well.

The diagonal blue line shows the profile of the cost to produce steam from natural gas. It is based on CAPEX and OPEX estimates, a high combustion efficiency (~85%), and minimal flue gas clean up (i.e., no cost for sulphur, ash, or particulate mitigation) [21]. Three points are highlighted on that line indicating reference case prices in the U.S. Energy Information Administration’s 2017 Annual Energy Outlook in current and future timeframes [22].

Fig. 8 shows that nuclear generators can provide cost competitive steam. The anticipated levelized cost of electricity from a nuclear reactor is in the range of $35–$45/MWh [23], therefore the range between the orange dotted line and the brown dashed line is the anticipated cost of steam generated from nuclear energy. It is less expensive than from natural gas at all natural gas prices above $2.00–$3.00/MMBtu depending upon where in the range the nuclear cost of electricity falls. Current industrial natural gas prices in the U.S. are higher than that range as are future price projections.

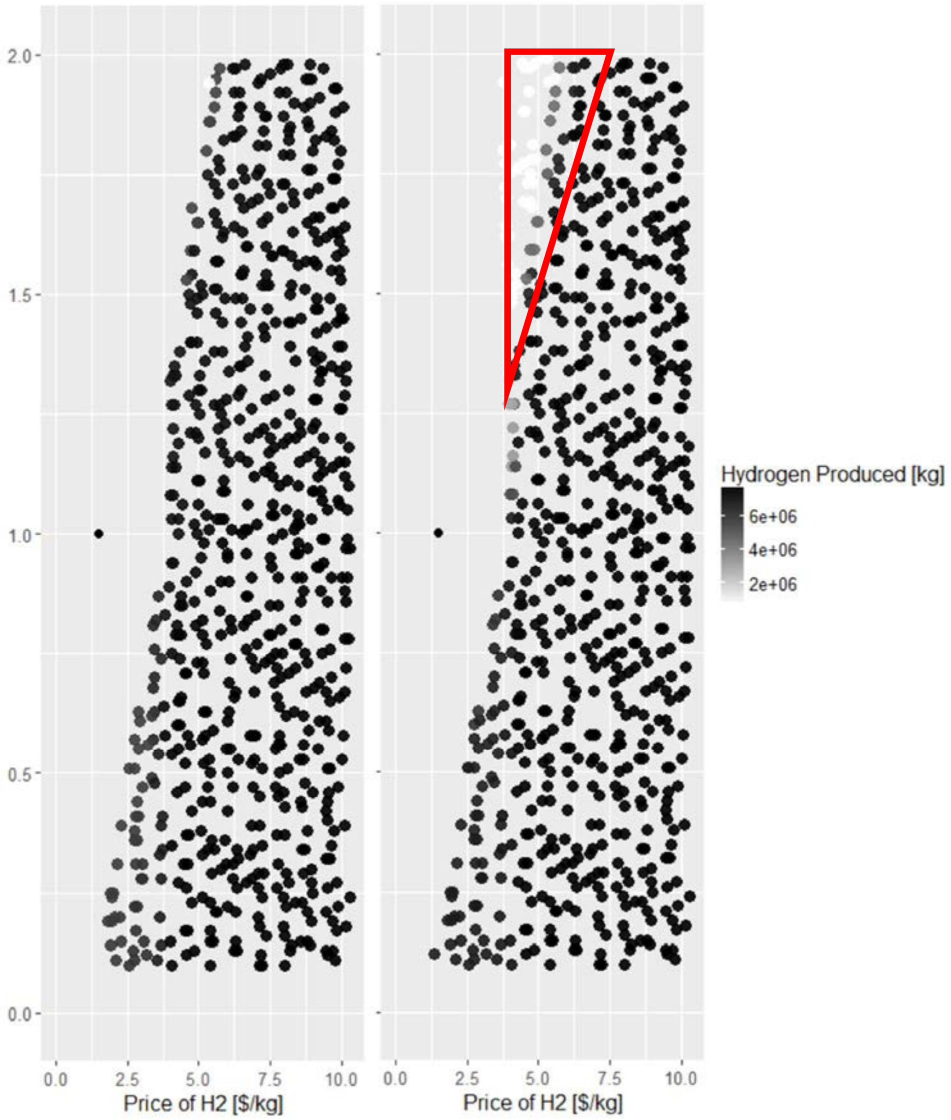

FIG. 8. Optimal annual hydrogen generation for the LTE scenario at various hydrogen prices and electricity price multipliers with two different electrolyser prices and efficiencies [9]. Triangle highlights conditions that include electrolysis only under low cost electrolyser parameters: Projected high cost electrolyser parameters (left); low cost electrolyser parameters (right); $50/kWyr capacity payments.; Solid black dot at $1.47/kg and 1.0 indicates reference case hydrogen and electricity prices.

This work shows that N–R HESs can provide benefits to the grid and be economically attractive in situations with high electricity price volatility. They can be especially economically attractive if the industrial process has a low capital cost and be turned on and off easily. N–R HESs with industrial processes that can utilize nuclear generated heat are also more likely to be economically attractive than those that use electricity exclusively because the overall thermodynamic efficiency is higher.

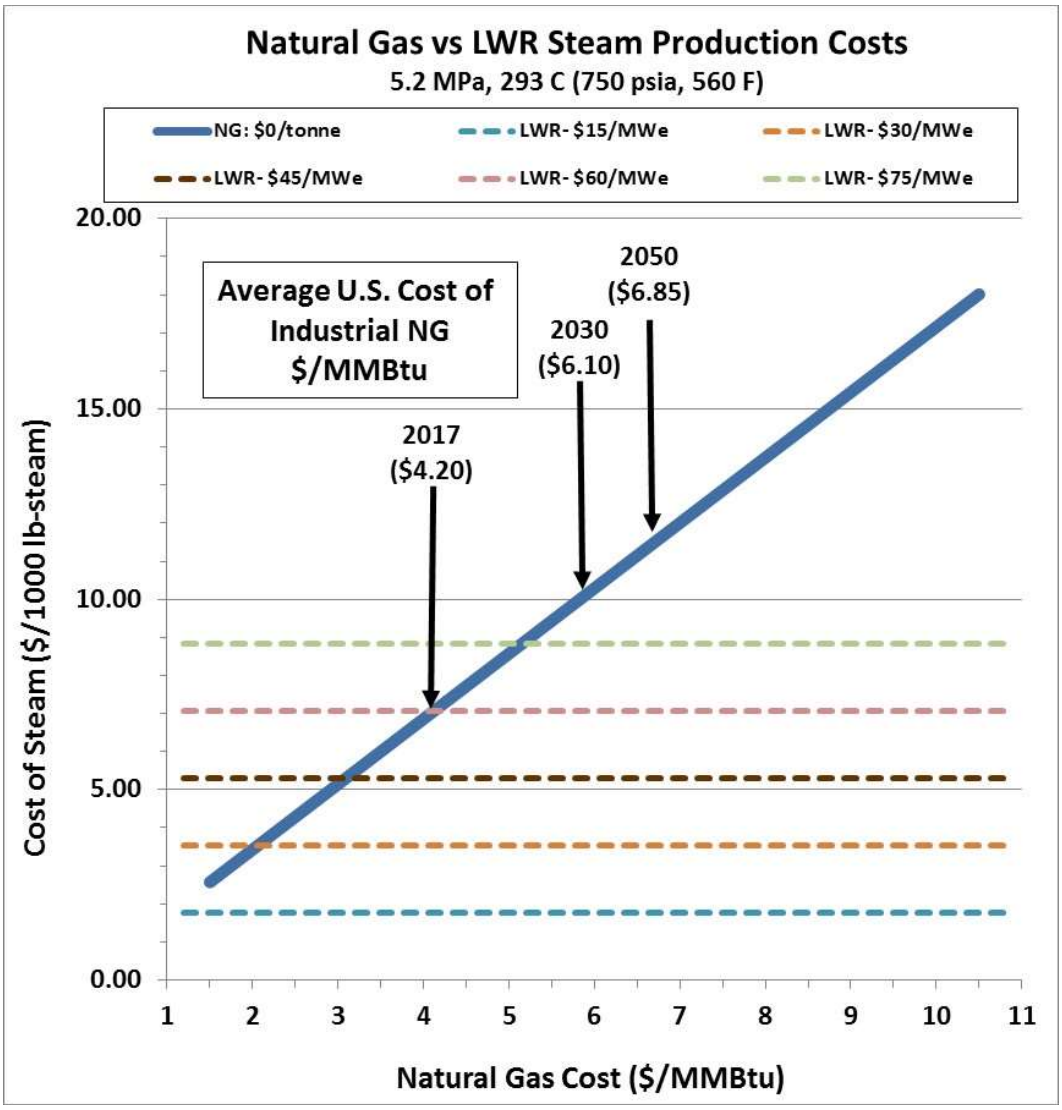

FIG. 9. Comparison of cost to produce steam from nuclear heat and natural gas combustion.

6. OPPORTUNITIES FOR FUTURE WORK

The Nuclear Innovation: Clean Energy Future (NICE Future) initiative was recently launched under the Clean Energy Ministerial[15] to focus on existing and new opportunities for nuclear energy. The goal of the NICE Future initiative is to initiate a dialogue on the role that nuclear energy can play in bolstering economic growth, energy security and access, and environmental stewardship. In support of that goal, the initiative has several strategic objectives [24]:

- Bring nuclear energy from traditional, nuclear only for a to broader multilateral discussions on clean energy at both the ministerial and working levels;
- Engage both nuclear and non-nuclear energy policy makers and stakeholders in a discussion on the role of nuclear energy in integrated clean energy systems of the future;
- Ensure energy policymakers are informed of the opportunities and challenges of the full range of options needed to meet global clean energy goals — covering areas of technology feasibility, economics and financing, and stakeholder perspectives.

[15] The Clean Energy Ministerial is a multinational organization that encourages a transition to a clean energy economy. It provides a forum to promote policies and programs and share experiences. Participants propose and select initiatives based on common interests.

Future analysis, research, and development on N–R HESs can support that goal by identifying benefits and challenges for this advanced nuclear energy technology that can support reliability and resilience for both the electricity grid and in the industrial sector. Each specific location will have its own opportunities and challenges. The analyses reported here assume generation mixes that include a high percentage of flexible natural gas power generation and projected U.S. natural gas prices. Locations with higher natural gas prices and less flexible generation may have different opportunities to achieve a reliable and resilient electricity system, and potentially have stronger economic drivers for N–R HESs and their ability to dispatch energy between electricity generation and an industrial process.

Several analysis opportunities would help quantify the benefits of nuclear generation — both independently and as part of N–R HESs. One opportunity is analysis of the level of real inertia required to manage frequency on the grid especially in situations where most of the generation is connected via inverters (e.g., where PV and wind generation is a large fraction of the total). By spinning turbines to produce electricity, nuclear generation inherently includes real inertia and can support those needs. Understanding that value is a first step toward compensating suppliers for it.

A second opportunity is the benefit of having always operating energy suppliers that do not require frequent supplying of fuels. Most nuclear technologies require fuel deliveries annually or less frequently and wind and PV do not require any fuel deliveries. Therefore, both have a higher likelihood of operating during times of system stress when delivery infrastructures are either constrained or cut off. Understanding that value can be a first step toward markets to provide it. A third opportunity is understanding the benefits of nuclear and renewable technologies, and N–R HESs, to hedge against fuel price uncertainty. Historically, energy prices have been volatile and short term volatility has put pressure on national economies. Since N–R HESs are designed to adjust the product mixture based on the market prices, they allow the owner to hedge against that volatility. The ability to flex could also benefit market operators and regulators because they would be able to design markets and justify investment decisions recognizing the price ceiling that an N–R HES would provide.

Other opportunities include responsive loads and development of alternative thermal energy sources for industry. The H2@Scale concept involves development of water electrolysis to produce hydrogen as a responsive load that can utilize low priced electricity to generate hydrogen that can then be used for a variety of industrial and transportation services as well as providing seasonal energy storage for the grid [25].

Alternative thermal energy options could diversify the source of thermal energy for industry. These sources include use of electricity in heat pumps, direct use of solar or geothermal energy, and use of nuclear energy [7]. Examples of industrial processes that use heat include minerals production; concentration, evaporation, and drying; petroleum refining and separations; thermal desorption processes; pulp and paper processes; and forest product drying and pyrolysis. Because many require higher temperature heat, advanced, higher temperature, nuclear reactors including the very high temperature gas cooled reactor which can delivery hot helium up to 950°C could be beneficial as well as molten salt reactors that can provide heat at temperatures up to 800°C [7]. In addition, new heat distribution systems, thermal energy storage options, and integrated heat exchanger chemical reactors could increase thermodynamic efficiency and increase opportunities for integration.

DISCLAIMER

This work was authored in part by Alliance for Sustainable Energy, LLC, the manager and operator of the National Renewable Energy Laboratory for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Office of Strategic Programs. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

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RESILIENT INTERCONNECTED MICRO ENERGY GRIDS FOR ENERGY AND TRANSPORTATION INFRASTRUCTURES

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Abstract

The deployment of smart energy grid (SEG) infrastructures are planned to be implemented in Canada to provide reliable and sustained energy supply with a reduced carbon footprint. SEG includes distributed energy generation including thermal, electricity and gas, and energy storage, as well as intelligent and distributed control systems. In order to maximize resiliency, SEG is composed of interconnected micro grids which allows dynamic and adaptive integration of thermal, gas, electricity, water and transportation networks to meet target loads with suitable conversions, co-generation, and storage strategies. Intelligent modelling and simulation environment is proposed and used to facilitate the design and implementation of such dynamic superstructures with local and global performance optimization. The proposed modelling and simulation environment can provide decision making capabilities to manage data gathering and analysis functions and map to static and dynamic models of SEG components. This will support the design, control and operation of a SEG in a distributed manner, along with the integrated applications. SEG deployment requires collaborative decision making and distributed control architectures with a distributed knowledgebase to support different views (e.g. utilities, OEM-HEV, consumers). The decision making will support the automatic and dynamic identification and evaluation of control and protection boundaries and operational scenarios of micro energy grids with renewable technologies and distributed energy generation nodes. The proposed SEG architecture will support different business models related to practical implementation of different technologies and components within the SEG architecture. The proposed intelligent and distributed modelling and simulation environment will be used to evaluate and optimize number of design and operational scenarios and functionalities. SEG with interconnected micro energy grids will enable Canada to be a leader in smart energy and resilient transportation infrastructures with low carbon footprint and improved efficiency and reliability.

1. INTRODUCTION

Canada is witnessing demand increase in electricity and energy. The deployment of energy systems and the utilization of energy has direct impacts on climate changes. Hence, governments and industries are strongly seeking appropriate solutions and investments to increase the penetration of renewable energy technologies, which will support economy growth and reduce environmental stresses. The renewable energy sources includes: solar, PV, wave, tidal, fuel cell, biogas, and hydrogen. Renewable energy technology, including PV and wind, are becoming more economic and feasible [1,2]. Small isolated standalone integrated AC–DC grid power systems are widely deployed to provide clean energy based on photo voltaic and fuel cell with a local energy storage ranging in sizes from 15 kW to 1500 kW [3,4]. The microgrids are commonly implemented for remote communities, transportation, industries, integration with utility grids, heating and air conditioning, water network pumping, and urban infrastructures [5]. In these microgrid setups, diesel generators are the typical backup source of electricity.

The deployment of SEG will enable the shift to adaptive energy superstructures based on interconnected micro energy grids (MEGs) with renewable energy technologies and energy storage systems. The main constraint to deploy SEG and MEG is the capital costs involved as well as regulations and standards to govern the deployment. An integrated SEG/MEG modelling and simulation tool is important to evaluate different design and operational alternatives and control strategies to achieve optimum sizing, technology selection, and optimum control. The proposed modelling and simulation will support utilization for transportation electrification, including hybrid electric vehicle (HEV).

This paper discusses modelling and simulation to support engineering design and planning of resilient SEG and interconnected MEGs. The proposed modelling is based on knowledge structure of energy nodes on the basis of Energy Semantic Networks (ESN). Distributed SEG data management module includes: grid physical system models; grid assets and components models; power/energy system models; grid asset integrity and reliability models; safety and protection models; and operation and control models.

It is important to link SEG with practical business model to deploy and manage the transition of energy infrastructure and technology deployment.

Technological infrastructures will be utilized to automatically and dynamically identify practical distribution and partitioning strategies of micro energy grids with the ability to define operational and alternative scenarios based on key performance indicators and protection and control strategies.

2. INTERCONNECTED MICRO ENERGY GRIDS

An energy semantic network (ESN) is proposed as a dynamic and adaptive superstructure to model energy supply and production chains [6]. It is based on resilient interconnected MEGs that can support local loads in each MEG, can supply energy back to energy grids, and can provide flexibility to exchange energy among interconnected MEGs. ESN provides dynamic and intelligent ways to integrate energy generation, energy storage, and energy loads. ESN is used also to integrate electricity, gas, and thermal grids with possible conversion among them. ESN is also used to interconnect MEGs with transmission and distribution lines. Fig. 1 shows the proposed ESN to model Transmission Lines (TL) / Distribution Lines (DL) of electricity networks (EN), gas networks (GN), thermal networks (TN), water networks (WN), and transportation networks (RN). It also includes energy storage in each layer: RNS: Transportation Network Storage, WTN: Water Network Storage, TNS: Thermal Network Storage, ENS: Electricity Network Storage, and GNS: Gas Network Storage.

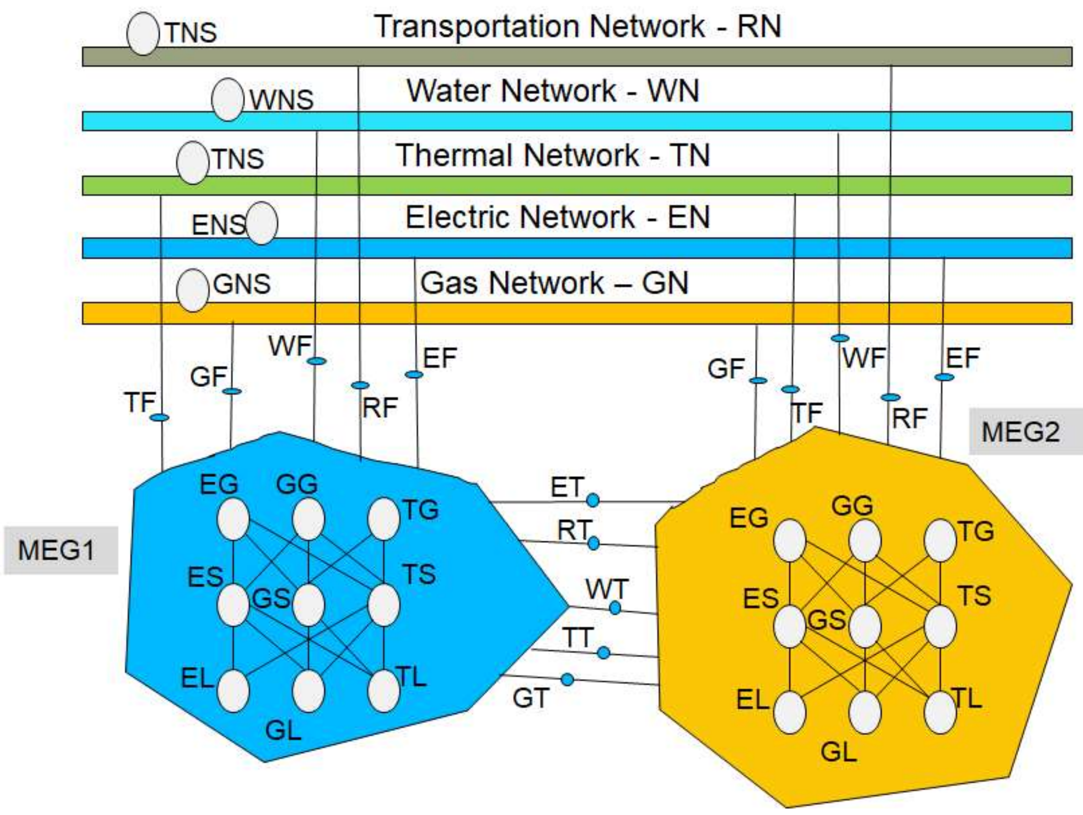

FIG. 1. Energy semantic network (ESN) with interconnected micro energy grids.

ESN includes the integration of transmission and distribution lines with MEGs via electricity feeder lines (EF), gas feeder lines (GF), thermal feeder lines (TF), water feeder lines (WF), and transportation feeder lines (RF). ESN includes nodes of energy generation: electricity generation (EG), gas generation (GG), and thermal generation (TG); energy storage: electricity storage (ES), gas storage (GS), and thermal storage (TS); and energy loads: electricity loads (EL), gas loads (GL), and thermal loads (TL). The interconnection between MEGs includes: electricity transfer lines (ET), thermal transfer lines (TT), gas transfer lines (GT), water transfer lines (WT), and transportation transfer lines (RT). ESN static structures are synthesized and dynamically tuned with computational intelligence techniques using real time data and simulation.

2.1. SEG infrastructures

Energy infrastructures include energy generation and multigeneration, transmission and distribution infrastructures, and integration with utilization networks from transportation, buildings, industries, commercial buildings and infrastructures, as shown in Fig. 2.

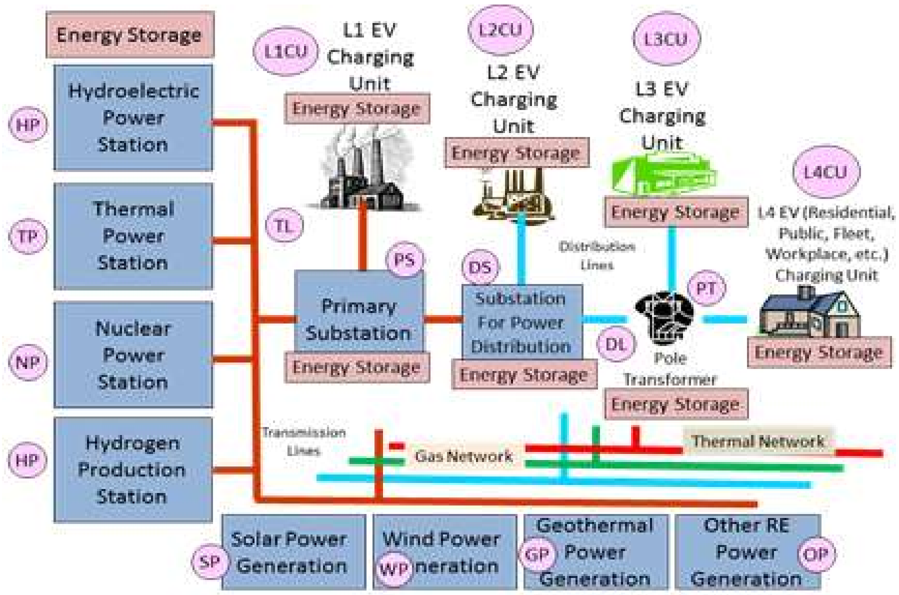

FIG. 2. Energy infrastructures [6].

2.2. Key performance indicators

The performance of the target SEG is evaluated in different levels: overall micro grid, energy generation, energy storage, power lines, power compensators, regulators, FACTS devices, controllers, sensors and loads [7]. An initial study has been performed to investigate key performance indicators to evaluate micro grids. The ultimate goal of analysing SEG performance indicators is to identify the best set of micro grid parameters to meet the following multi-objective optimization criteria: minimum change in the fundamental frequency load bus voltage under steady state conditions; minimum feeder current with maximum DC generation and maximum AC system grid capacity release; minimum feeder power losses, due to reduced fundamental RMS current magnitude; minimum dominant harmonic distortion in the host electric grid using the hybrid power filter. Simulation results showed optimized performance of the proposed algorithm.

3. SMALL MODULAR REACTOR IN MODERN MICRO GRID

3.1. Small modular reactor

A small nuclear plant, also known as small modular reactor (SMR), is a small scale nuclear power plant in the order of 300 MWe, as defined by the International Atomic Energy Agency (IAEA) [3]. SMR is considered as one type of distributed generation technologies that can provide sustained energy supply for critical and remote applications.

A small module reactor can be integrated within micro grid to provide resilient energy supply to meet target load profile. Table 1 [3] shows key parameters of SMR technologies.

TABLE 1. DIFFERENT SMR TECHNOLOGIES WITH PARTICULARS

SMR NAME	TYPE	THERMAL CAPACITY	ELECTRICAL CAPACITY	FUEL	REFUELLING CYCLE
Westinghouse SMR	PWR	800MW$_t$	225 MW$_e$	<5% enriched U235	2 years
mPower	PWR	530 MW$_t$	150–180 MW$_e$	<5% enriched U235	4+ years
NuScale	PWR	160 MW$_t$	45 MW$_e$	4.95 % enriched	2 years
IRIS	PWR	300–1000 MW$_t$	100–335 MW$_e$	5% enriched U235	5 years
Gen4 (Hyperion)	FNR	75 MW$_t$	25 MW$_e$	Uranium nitride	10 years (replaced)
4S	LMR	30 MW$_t$	10 MW$_e$	19.9 % enrichment	10–30 years

3.2. Micro grid with small modular reactor

The integration of SMR within micro grid architecture can provide resilient energy solution to meet different load profiles with different capacities. Micro grid with SMR can also provide balanced heat and power supply and can be designed, configured, and controlled to meet target demand. Fig. 3 illustrates the proposed generalized architecture of a micro grid, which includes micro turbine, solar PV, wind power, fuel cell and the reciprocating engine, as well as energy storage system. In this design scenario, solar and wind couldn't provide continuous stable power supply, while the reciprocating engine and micro turbine are able to provide constant output power. However, reciprocating engines have negative environmental impact.

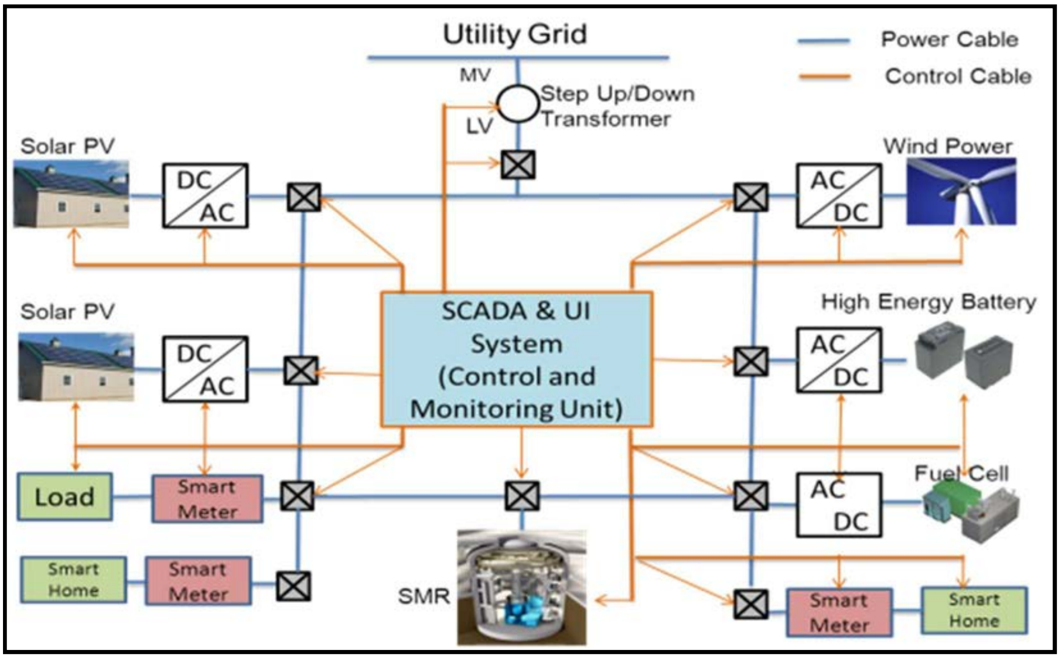

FIG. 3. Micro grid with small modular reactor [3].

SMR technology could be selected based on sized and technology specifications. Examples of SMR technology includes: Light water reactor (LWR), fast neutron reactor (FNR) and graphite moderator reactor (GMR) are the main categories of small modular reactors and the size could be from 10 MW_e to 300 MW_e.

4. MEG FOR TRANSPORTATION INFRASTRUCTURES

Interconnected micro energy grids are adopted to supply sustained energy to transportation, such as railways, as shown in Fig. 4. Energy is supplied from the grid and complemented with renewable energy and energy storage to ensure resilient transportation infrastructures with reduced overall energy costs and operating risks. Fig. 5 shows a distributed control architecture with supervisory control in each micro energy grid to provide optimum performance of interconnected micro energy grids based on the dynamic load profile of trains.

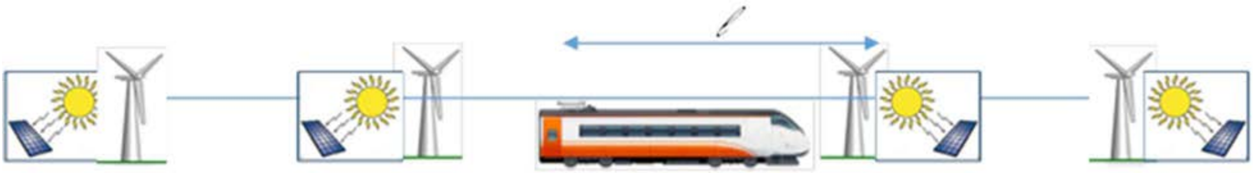

FIG. 4. Interconnected MEG for railway transportation.

As can be seen in Fig. 6, when train is drawing power, during part of the time power is supplied by grid, solar cell and wind turbine. These intervals are decided by an optimization algorithm. For now, a rough optimal value has been estimated.

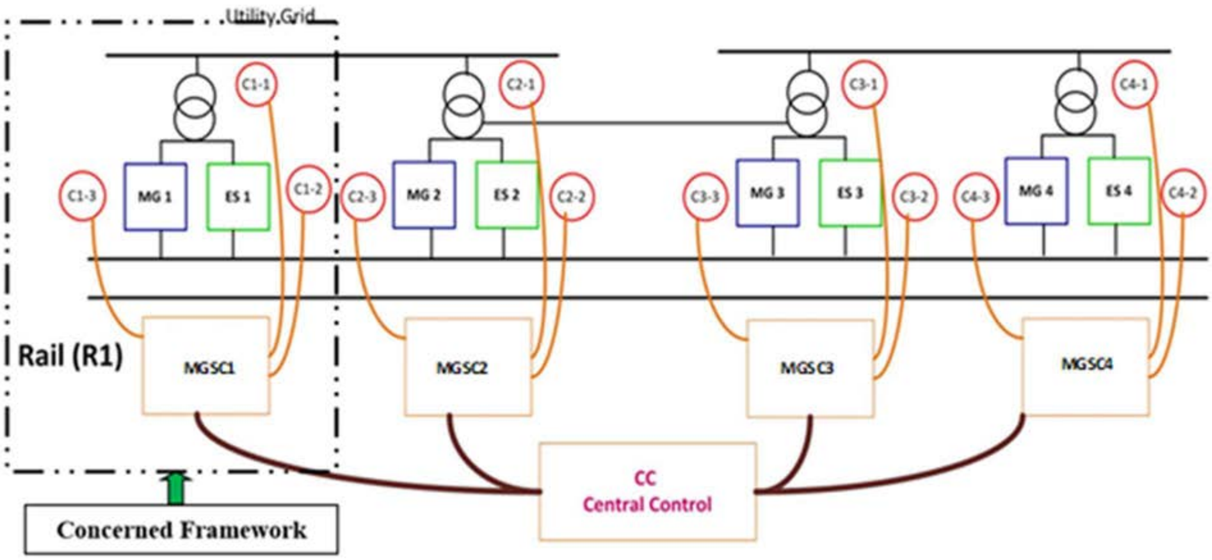

FIG. 5. System design of interconnected micro energy grids for railway.

5. INTEGRATED MODELLING AND SIMULATION

One important feature in the proposal is to provide synchronization between real time grid data and simulation engine. This is important in twofold: (a) start simulation scenarios with initial conditions using real time data from the grid and (b) fine tune simulation models using real time data. This is achieved by building an intelligent interface program that captures real time data from the grid and maps to the state variables in the simulation engine, which will tune simulation models using genetic programming with limited iterations to reduce the error between simulation results and real time. On the other side, it is possible to predict the future status of the grid loads/demands by using smaller time steps of the simulation starting from the current condition of the grid as the initial condition. This will provide accurate estimation of loads/demands and identify/plan the best ways of recovery operation. In order to support decision making, intelligent algorithms will be developed to convert simulation data into qualitative models with symbolic representations. In terms of the simulation engine, and for interoperability purposes to support the wider range of commercialization, the simulation interface will be developed to interface with major simulation engines available in the market such as DIgSILENT PowerFactory, CYMDIST, ETAP, Paladin Design, EMTP/PSCAD, SimPowerSystems (SPS) and PSS1. The idea is to allow parameter passing between the simulation engine and the simulation interface program in two ways so that simulation results are captured in each time step and update the database for tuning simulation models using the specified data analysis techniques.

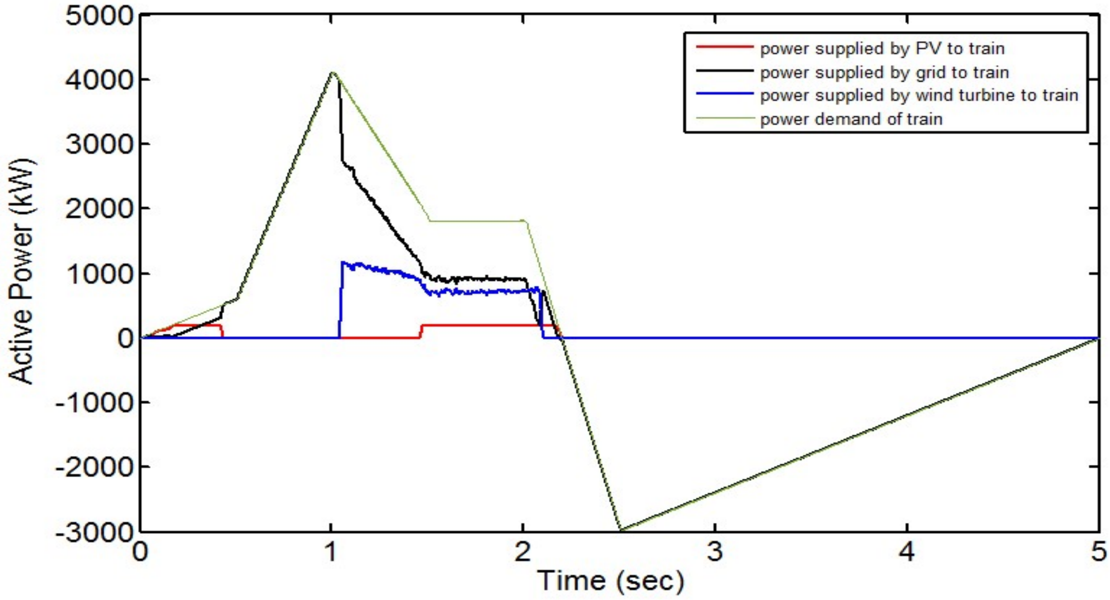

FIG. 6. Power analysis of interconnected micro energy grids for railways.

6. IEC61850 STANDARD

IEC 61850 standard was originally developed in 1997 by EPRI/IEEE and IEC TC 57, with the mandate to provide an international standard to support implementations of smart grids with unified structures. It was used to standardize power utility automation systems (PUAS) and substation. Later, it was extended to cover the integration and deployment of DERs. Fig. 7 shows overview of IEC61850.

7. SAFETY/PROTECTION OF SEGs

The proposed modelling and simulation will support real time safety verification based on an advanced safety design approach. The concept of independent protection layers, or IPL, will be utilized to evaluate different risk scenarios and map to a set of IPLs based on risk level, propagation time and cost involved. Layer of resilience analysis (LORA) is used to support analysis and design of resilient micro energy grids. Independent resilience layers (IRLs) are used to achieve resilient MEGs by integrating different functions and systems to achieve target resiliency with sustained operation of interconnected MEGs. This can be complemented with safety integrity level (SIL).

This module will enable the development of safety design and hierarchical risk index based on the reliability of grid components [5,8], loads, historical maintenance involved and future operational plans/forecasting, as shown in the figure below. This will allow the dynamic tuning of risk index as linked to different components and displayed in the user interface in real time to enable operators and users to understand risks involved with different energy supply scenarios and to take suitable recovery actions.

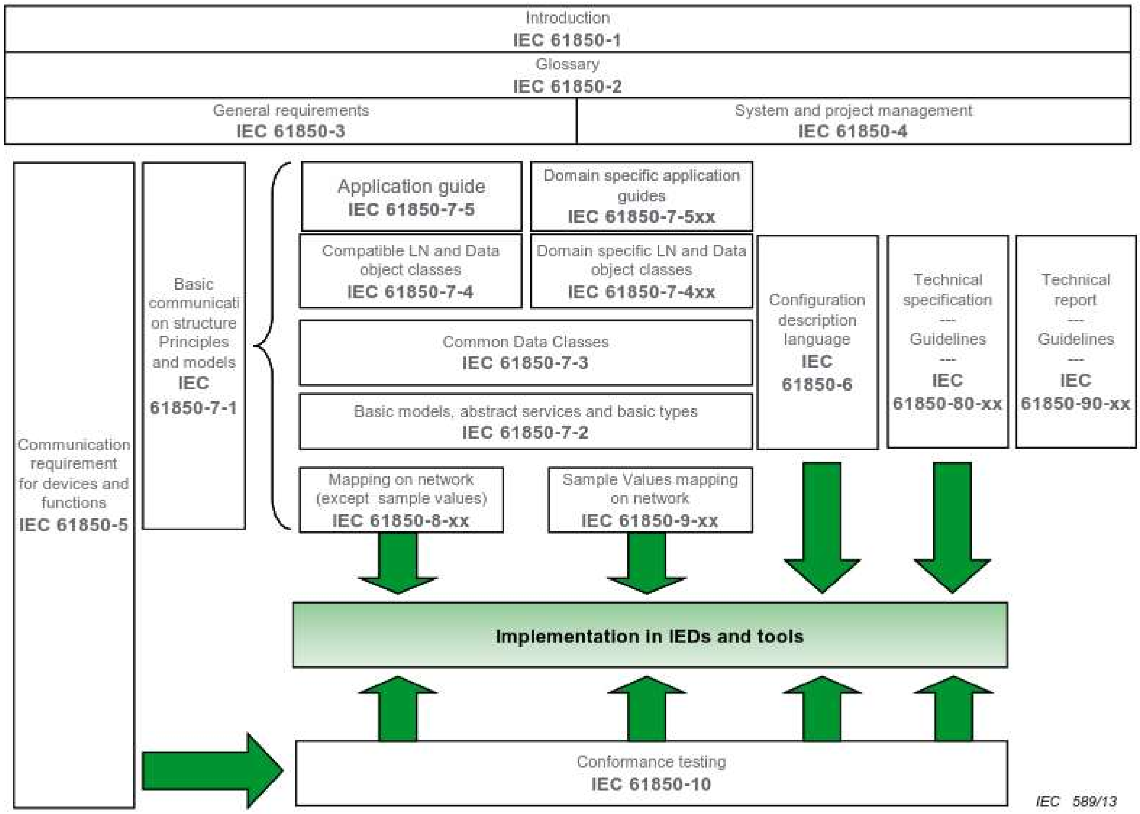

FIG. 7. Overview of IEC61850.

7.1. Resiliency using fault semantic network (FSN)

The concept of a semantic network was first proposed by Richens in 1956 [9]. It is a network structure that represents relations between concepts. The concept of a semantic network was further developed by Collins and Quillian in 1969 [10] who introduced semantic network in a tree structure (directed or undirected graph) consisting of nodes and arcs. The nodes represent concepts and the connections show relations between nodes. Fault semantic network (FSN), originally realized by Gabbar in [6], is a means of representing fault knowledge based on relationships between objects. In FSN, the nodes correspond to different faults/causes/consequences and the links between them describe the dependencies. Initially, a FSN is constructed based on the ontology structure of fault models on the basis of process object oriented methodology where a failure mode (FM) is described using symptoms, enablers, variables, causes, consequences and repair actions. Quantitative (probabilistic) or qualitative rules are associated with each transition of the causation model within FSN. Fig. 8 shows the construction and maintenance process of FSN to support MEG engineering design and management.

7.2. Framework for Safety and Protection of SEGs

The proposed safety and protection framework is based on identifying all possible fault propagation scenarios using FSN in view of MEG static and dynamic models, and estimating dynamic risks associated with each fault propagation scenario while mapping independent protection layers within each fault propagation scenario. FSN will be dynamically tuned with real time data using computational intelligence algorithms, as shown in Fig. 9.

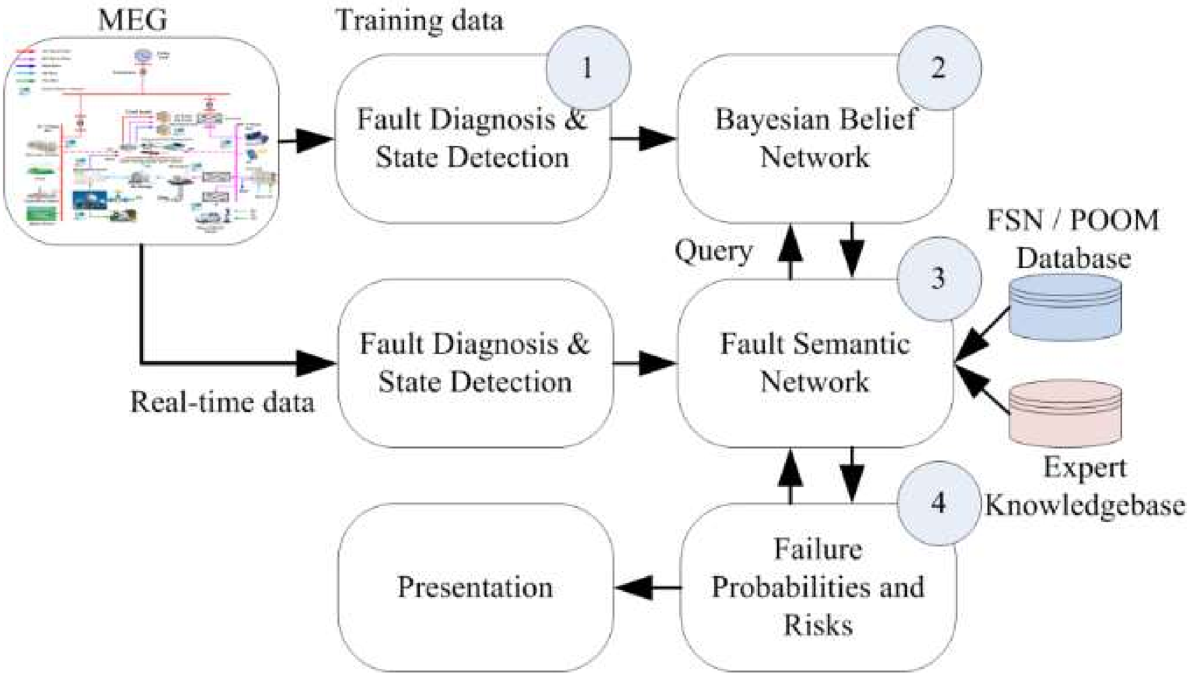

FIG. 8. Process to construct fault semantic network of interconnected MEGs.

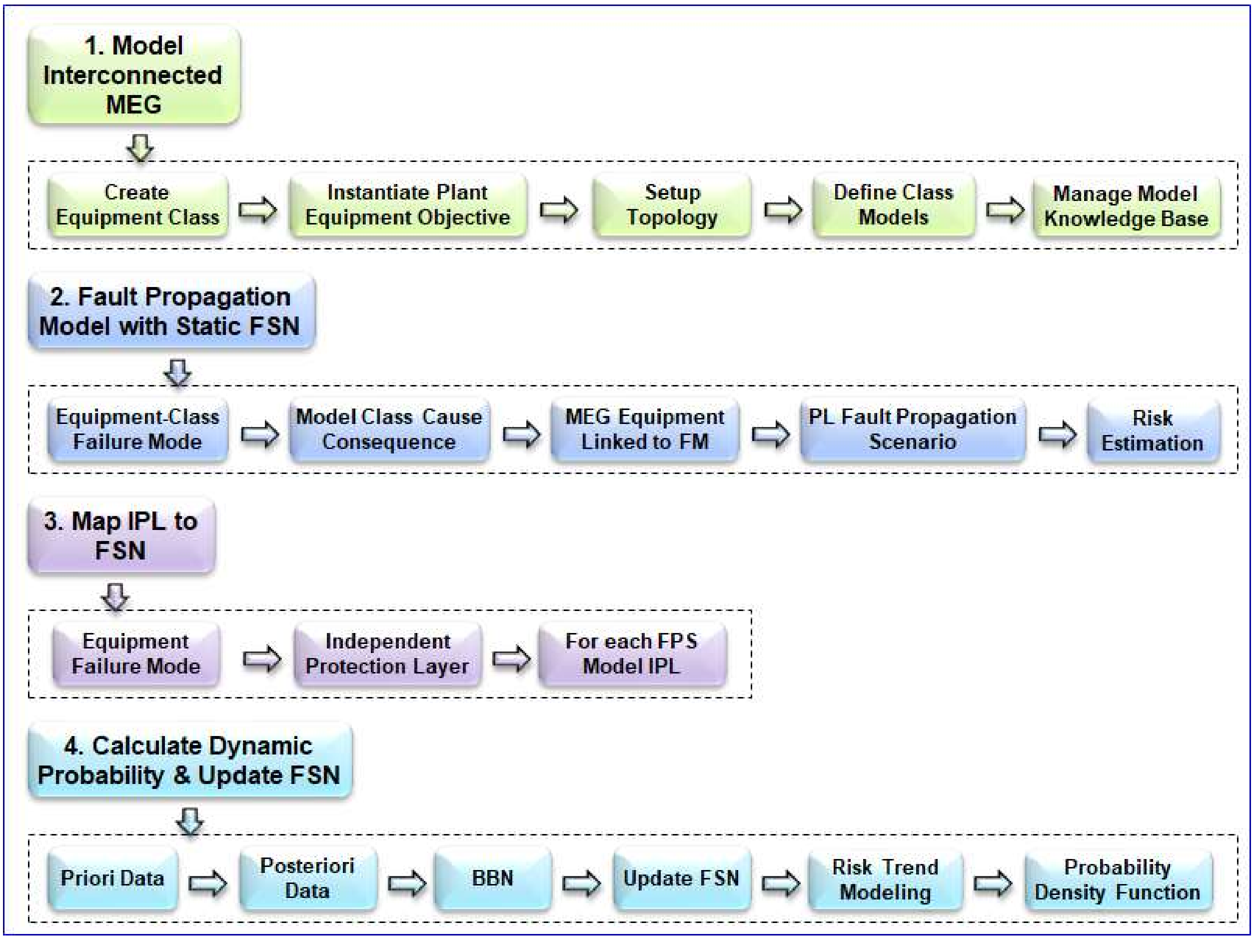

FIG. 9. Framework for FSN based safety and protection design of MEGs.

8. CONCLUSION

This paper presented overview of challenges and opportunities of SEGs and their implementation with interconnected micro energy grids using adaptive modelling of energy grids using energy semantic networks. The proposed modelling technique is able to model interconnected micro energy grids to meet local and regional demands based on available energy systems, conversion technologies, storage, and energy supply strategies. Integrated interconnected micro energy grids are proposed to support energy and transportation infrastructures, with intelligent and distributed control architecture with supervisory control to ensure local and global optimum performance. To achieve high performance and resilient SEG architectures, a novel approach is proposed to integrate ESN with fault semantic networks based on probabilistic and deterministic safety assessment frameworks to achieve resilient energy infrastructures. A case study of an integrated small modular reactor within micro grid is shown to demonstrate the possibility of nuclear – renewable hybrid energy systems to support energy and transportation infrastructures in sustainable communities.

Acknowledgement

The author would like to acknowledge all team members at ESCL-Energy Safety and Control Lab, at UOIT, for their support and contribution to this work.

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HTGR AND RENEWABLE ENERGY HYBRID SYSTEM FOR GRID STABILITY – ASSESSMENT OF PERFORMANCE, ECONOMICS AND CO2 REDUCTION

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Abstract

The hybrid system concept integrating an HTGR based nuclear cogeneration plant and variable renewable power sources (solar and wind) is characteristic of three major features: 1) The system provides grid stability by the nuclear plant compensating short and long term changes of the renewable power. This is achieved through nuclear reactor control based on HTGR intrinsic design features. 2) The system can be cost effective as the nuclear reactor remains baseload while varying the ratio of cogenerating products. This is achieved without adding significant complexity or cost to nuclear plant operation. The cost with traditional grid stability measures such as battery and standby power plants otherwise required to back up renewable power is saved. 3) The system provides nuclear plant as peaking power and cogeneration of hydrogen, enabling nuclear energy to do more than the traditional baseload power generation. The 2018 Strategic Energy Policy of Japan calls for promoting innovation of nuclear technology including coexistence with renewable energy and multipurpose such as hydrogen production. Given the significant progress of HTGR development and of renewable energy installation seen in the country, the hybrid system is expected deployable supporting the policy goals around 2030s.

1. CHALLENGES FACING NUCLEAR AND RENEWABLE ENERGY IN JAPAN

The Basic Energy Policy of Japan released in July 2018 [1] reaffirms the goals set in 2015 for nuclear energy to account for 20–22 percent and renewable energy 22–24 percent of the nation`s electric power supply in 2030. Fossil fuels, such as coal and gas, account for the rest.

Today, Japan remains heavily reliant on fossil energy. The most recent statistics for the year of 2017 showed that fossil fuels accounted for 83 percent of Japan's electricity, whereas renewables 15 percent and nuclear just 2 percent. The targets set in the new policy, particularly the nuclear target, are thus challenging to achieve in the wake of the 2011 Fukushima disaster which keeps most of the country's reactors offline while they undergo heightened safety review.

On the other hand, Japan aims to reduce its carbon emissions by 26 percent from 2013 levels by 2030 and by 80 percent by 2050. It is imperative that the contribution of nuclear and renewable energy to the power supply would have to be considerably increased in the long term.

To enable a large share of solar and wind power generation on electric grid, the imbalance between generation of these intermittent sources and demands have to be managed. On demand fossil fired plants and energy storages such as pumped hydro storage power, battery storages, smart meters, expanded grid interconnectivity, etc. are measures applied to stabilize the grid. Because of the low efficiency, say 10% for pumped hydrogeneration, and surcharge for equipment and operation required, these measures are estimated to add significant premium given in Table 1 to renewable generation costs of ¥15/kWh for solar and ¥20–30/kWh for wind in the level of technology projected to 2030 [2].

Existing nuclear fleets are exclusively of light water reactors PWRs and BWRs. Because they are relatively high in capital cost but low in fuel cost, these reactors are suited for continuous baseload generation rather than providing load follow. Other nuclear reactor designs such as HTGR may be considered to avoid adding CO_2 emission and costs to increasing the share of renewable power generation on the grid.

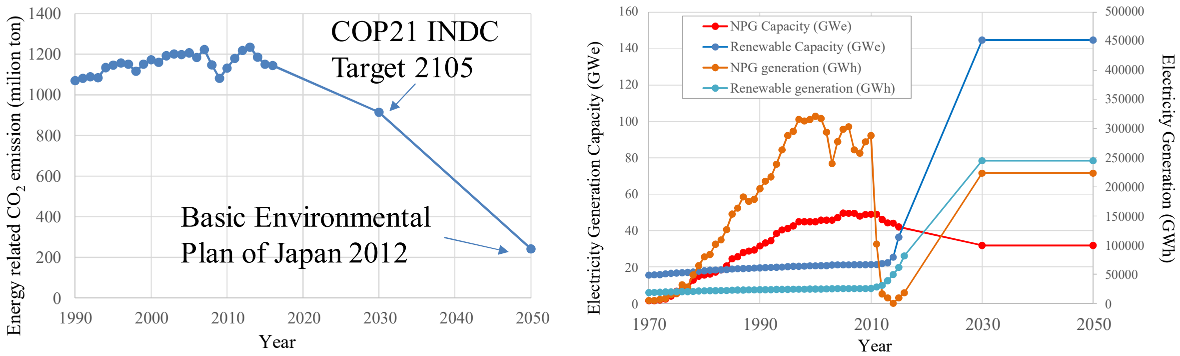

FIG. 1. Statics and policy of Japan`s CO_2 emission (left) and nuclear and renewable power generation (right).

TABLE 1. PROJECTED MANAGEMENT COST FOR VARIABLE RENEWABLE POWER GENERATION IN 2030

VARIABLE RENEWABLE POWER GENERATION	SHARE OF TOTAL GRID POWER GENERATION	COST OF POWER MANAGEMENT FOR RENEWABLE GENERATION
66 TWh	6%	4.5 ¥/kWh
124 TWh	12%	5.6 ¥/KWh

2. CONFIGURATION OF THE HTGR AND RENEWABLE ENERGY HYBRID SYSTEM

Fig. 2 shows the conceptual HTGR and renewable energy hybrid system and Fig. 3 provides a detailed schematic of the system process including operating parameters and essential control devices. The HTGR is based on the GTHTR300C design being developed in JAEA [3].. It is based on a prismatic core reactor and cogenerates power by direct cycle gas turbine and hydrogen by thermochemical iodine sulphur process. The HTGR plant is integrated with renewable power generation sources of solar, wind or both, at one connection point on the grid, thus forming the hybrid integrated system. The HTGR plant is designed to follow the variations initiated in renewable generation sources to provide constant power to the electric grid. Depending on specific event of load following, one or more of the four control mechanisms that are built in the GTHTR300C are used:

(a) Reactor coolant inventory control by actuating the flow valve IV;
(b) Turbine inlet temperature control by actuating the flow valve BV;
(c) IHX heat rate control by regulating flow circulator speed of the heat transport loop;
(d) Reactor outlet temperature control through reactor control rods.

The hybridization with renewable energy takes advantage of two intrinsic design features of the HTGR system, namely, the agile power manoeuvring of the gas turbine and the existential massive capacity of heat in the reactor graphite core. The former, performed through a new proposal of using the inventory and bypass control devices already built in the gas turbine, is found to be effective and efficient to compensate for the intermittent power generation including hourly to daily variation of renewable energy. The reactor thermal power remains at constant full power while the heat output is increased or decreased subject to the need of reactor power generation. On the other hand, the massive heat capacity stored the HTGR graphite core is shown to be sufficient to compensate for the perturbating power generation of renewable energy on a time scale of seconds to minutes and up to about 20 percent of the rated power output of the nuclear plant. Similarly, no additional control devices, only a new proposal of using the existing devices, are required to perform this control operation. These findings demonstrate the technical and economic potential of the HTGR system to maintain the stability of a grid being incorporated with significant portfolios of renewable energy power generation.

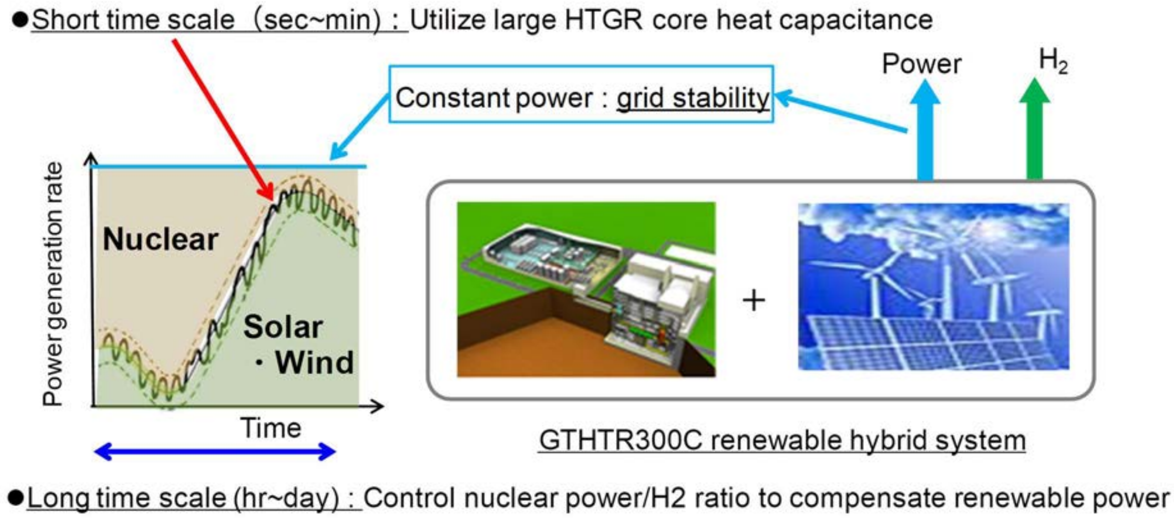

FIG. 2. Concept of the HTGR renewable energy hybrid system for grid stability.

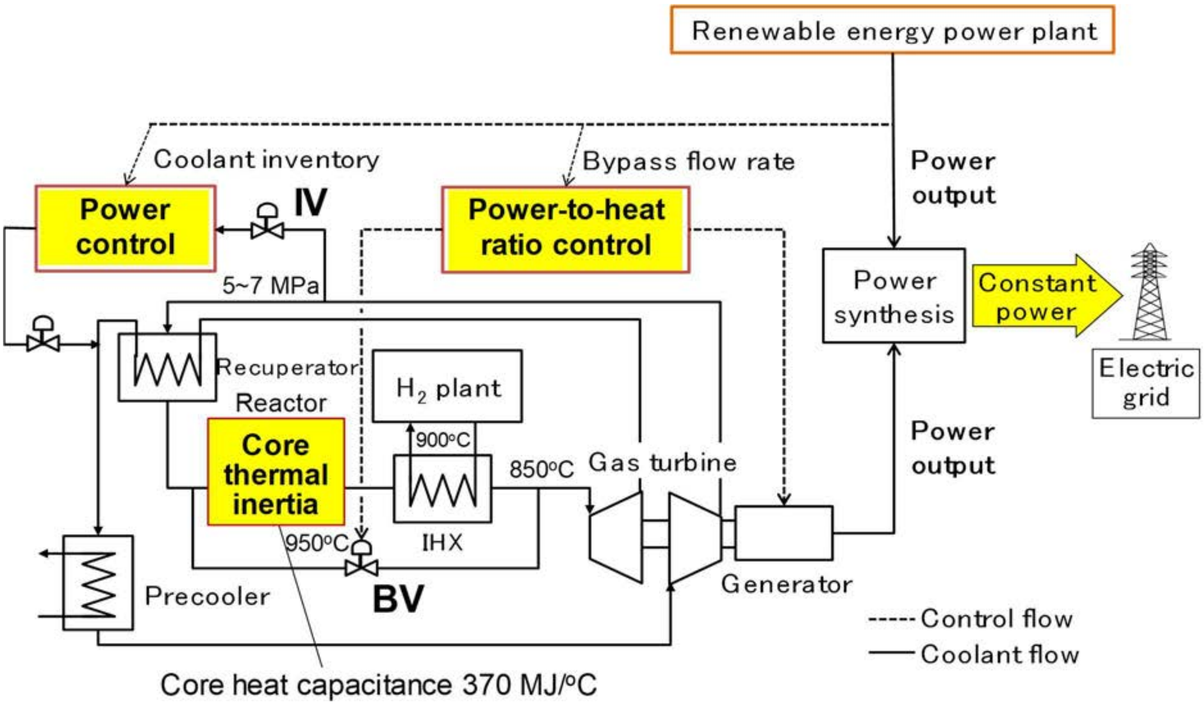

FIG. 3. Schematic of the HTGR renewable hybrid system based on the GTHTR300C design

3. PERFORMANCE ASSESSMENT

3.1. Variations in long (hour and day) time scale

In response to renewable power generation variations in hour and day time scale associated with solar system and often with wind system, the following strategies are employed for the control of nuclear plant designed to maximize nuclear plant economics while minimizing undesired impact of the frequent load following on nuclear reactor:

(a) Maintain constant reactor thermal power operation;
(b) Minimize transient thermal stress in reactor internal components;
(c) Minimize transient thermal stress in turbine blades;
(d) Maintain the high thermal efficiency of power generation.

In response to the renewable power variation, nuclear reactor helium coolant may be taken in or out of the primary circuit using the coolant inventory control system. Simultaneously, the IHX heat rate for the hydrogen plant is adjusted by the helium flow circulation rate of the heat transport loop that connects the reactor to the H_2 plant. In addition, the valve BV is adjusted to keep turbine inlet temperature unchanged. As seen, the reactor power and generation efficiency are kept constant at all time as intended in Fig. 4.

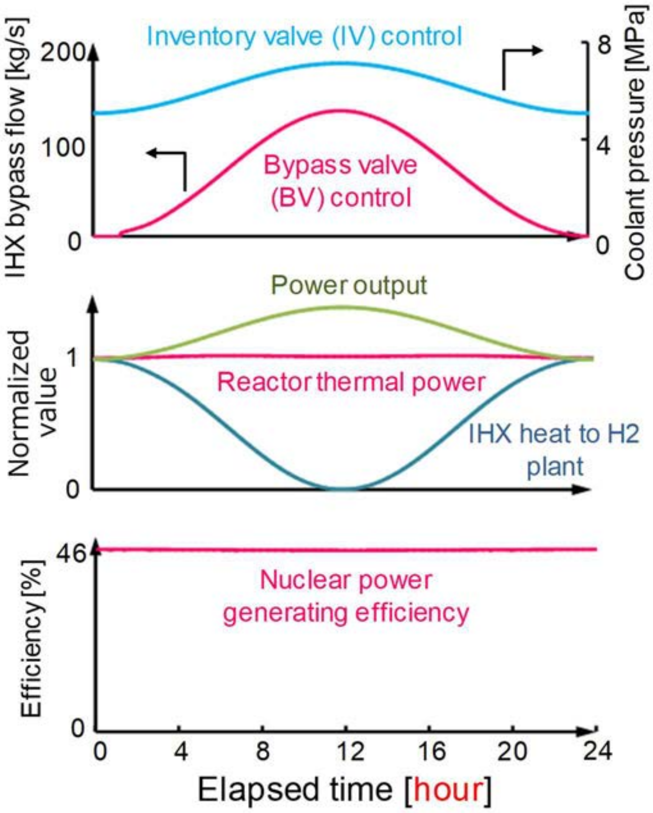

FIG. 4. Reactor response to daily renewable power generation variation.

3.2. Variations in short (minute and second) time scale

The operation strategy for the nuclear reactor to accommodate renewable power generation variation in minute or second time scale associated mainly with wind system take the advantage of intrinsic design feature of the HTGR core having a huge thermal capacitance due to massive amount of graphite used in the reactor core. For example, the core of the 600 MW_t HTGR has a thermal capacity of 373 MJ/K.

In addition, turbine speed is kept constant due to large grid connection. In case of absence of a large grid, turbine speed would be maintained by a turbine flow bypass valve (not shown in Fig. 3). Furthermore, the reactor reactivity control rods are not moved in response to small changes of reactor outlet coolant temperature to be encountered as long as the renewable power disturbance at short time scale is limited within ±20% of the nuclear rated power.

Fig. 5 is the simulation of nuclear reactor operation to renewable power change at the minute scale whereas the performance of the system to the second scale has been found similar. As can be seen, the reactor fission thermal power remains essentially constant at all time where the power generation of the reactor is varied by the extraction and storage of the heat in the reactor core to increase or decrease turbine power generation output. The power generation efficiency is slightly changed because of the turbine bypass used to maintain turbine speed, instead of assuming connection to large external grid.

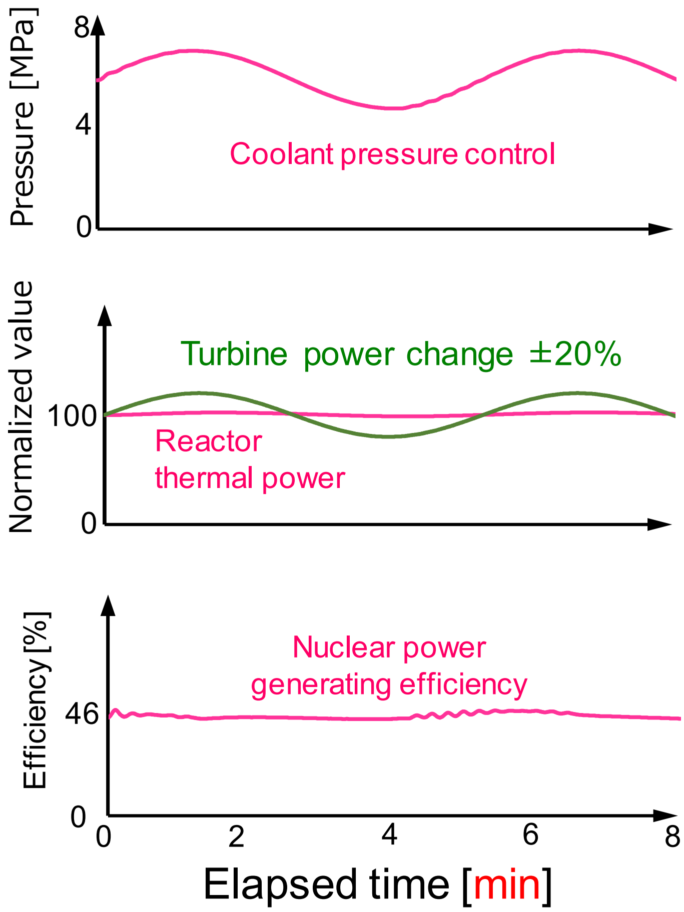

FIG. 5. Reactor response to renewable power generation variation of minute scale.

4. ECONOMICS ASSESSMENT

4.1. Estimation conditions

Table 2 lists the financial parameters used in the cost estimation. Discount rate, interest, and property tax are typical values to assess the cost of utility nuclear reactors in Japan. Since the life time of hydrogen plant is 20 years, the cost of one-time replacement of hydrogen plant is considered during the reactor life time.

The cost assumed the production parameters of the HTGR as given in Table 3. Additional assumptions for cost estimation include the following:

- The system is a centralized large scale nuclear hydrogen cogeneration production system sited in Japan.
- Hydrogen is produced is supplied to adjacent industrial user (e.g., oil refinery or chemical plant) on the site.
- Alternatively, an at gate cost is also given for liquefied and stored hydrogen product, ready to be transported by pipeline or trucks to the users.
- Hydrogen production process is the thermochemical S-I process.
- The cogeneration plant arrangement is that of GTHTR300C as shown in Fig. 3.

TABLE 2. FINANCIAL PARAMETERS

PLANT LOAD FACTOR	90%
REACTOR PLANT LIFE TIME	40 years
DEPRECIATION PERIOD	16 years
RESIDUAL VALUE	10%
HYDROGEN PLANT LIFE TIME	20 years (one replacement required)
DEPRECIATION PERIOD	10 years
RESIDUAL VALUE	10%
DISCOUNT RATE	3.0%
INTEREST RATE	3.0%
PROPERTY TAX RATE	1.4%

TABLE 3: GTHTR300C PARAMETER

REACTOR THERMAL POWER	MW_{th}	600
REACTOR OUTLET TEMPERATURE	^{o}C	950
GROSS POWER GENERATION	MW_e	204
REACTOR PLANT ELEC. LOAD	MW_e	6
H_2 PRODUCTION RATE	t/d	67
	Nm^3/h	31 800
H_2 PLANT HEAT CONSUMPTION	MW_{th}	170
H_2 PLANT ELEC. CONSUMPTION	MW_e	27.6
H_2 PRODUCTION EFFICIENCY	%	50.1

4.2. Summary of the cost estimates

The estimated costs of hydrogen and electricity cogenerated by the HTGR plant are shown in Fig. 6 and Fig. 7, respectively. These costs are compared with alternative hydrogen costs [4] and alternative power generation costs [2]. The cost of HTGR electricity is seen very competitive to those of low carbon generation sources used to load follow variable renewable power such as fossil and pumped hydro generation.

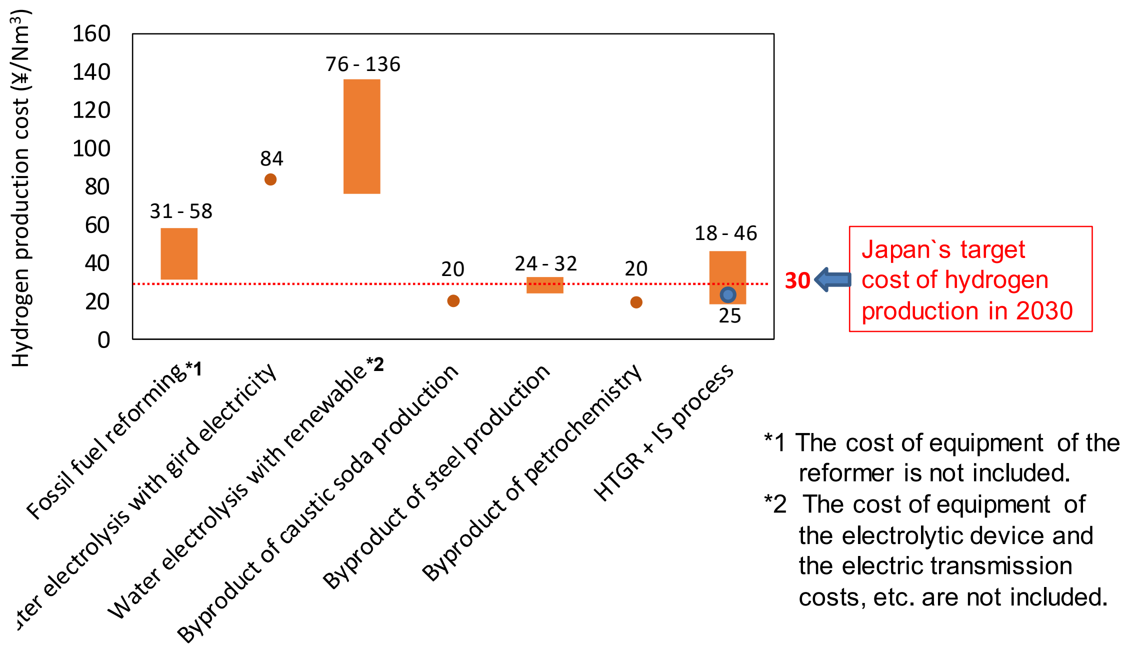

FIG. 6. Hydrogen production costs.

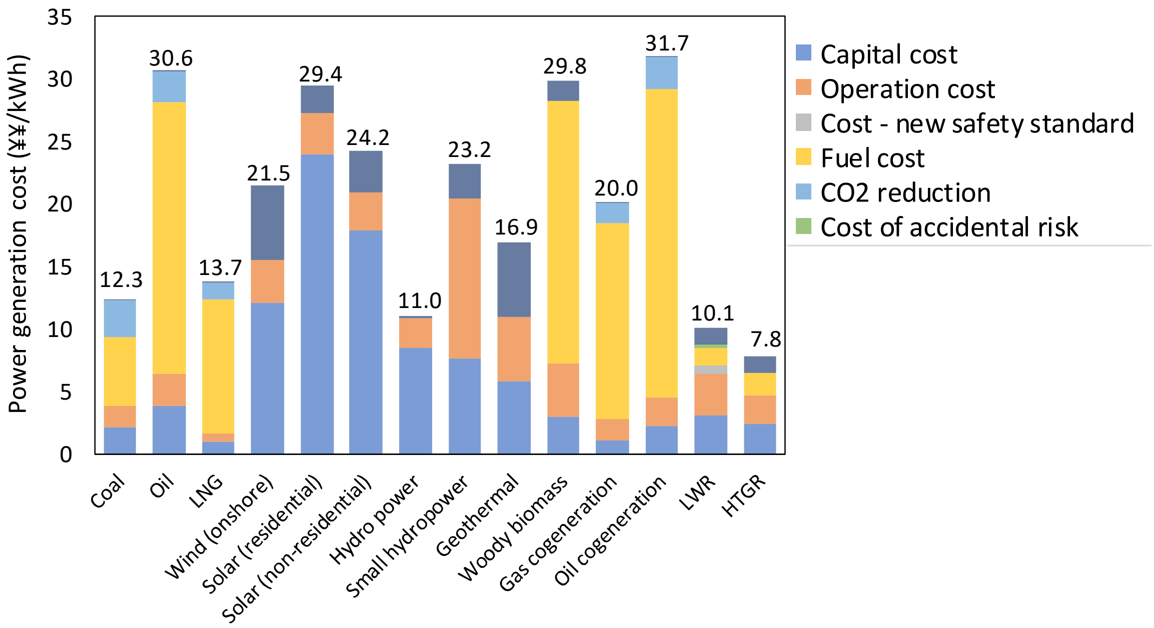

FIG. 7. Power generation costs of 2014 model year plants.

5. ASSESSMENT OF CO_2 REDUCTION

5.1. Meeting hydrogen demand

While the HTGR and renewable energy hybrid system generates grid electric power, the hydrogen coproduced by the HTGR is used for transport and stationary fuel cells and for steelmaking industry. Forecast hydrogen demands for these sectors in Japan are given in Table 4. It is assumed that 40% of the total hydrogen demand in 2050 is supplied by the HTGR. A total of 112 HTGR plants, each consisting of 4 units of the reactor, are required to supply this amount, of which 26 plants are installed in Japan and the rest in overseas. The hydrogen produced from overseas will be reverse imported for consumption in Japan.

TABLE 4. FUTURE HYDROGEN DEMAND IN JAPAN

	2030 [5]	2040 [5]	2050 [6]
TRANSPORTATION (FCV)	0.5	1.5	2.6
INDUSTRIES (fuel cells)	0.1	1.3	0.8
RESIDENTIAL (fuel cells)			7.5
POWER GENERATION		8.3	11.6
OTHERS			1.3
TOTAL	0.6	11.1	23.7

5.2. Power generation

The power is cogenerated by the 26 plants of the HTGR installed domestically for the production of hydrogen as described in Section 5.1. The total capacity is 21 GW_e used for variable power generation along with renewable energy. Additional nuclear baseload power generation is provided by LWR and FBR in 2050. The nuclear power generation capacity is assumed to increase from 30 GW_e in 2030 to 70 GW_e in 2050, making a large contribution to the 80% emission reduction goal by that year.

5.3. Heat supply to industries

Heat is demanded over a wide range of temperature by industries such as steel, chemical and petroleum and coal industries. It is assumed that 20% of industrial heat demands is supplied by the HTGR. A total of 22 HTGR plants required and the amount of CO_2 reduction is 68.1 Mton per year.

5.4. Total CO_2 reduction

HTGR provides renewable energy with grid stability due to its operation simplicity. This synergy adds a large role for nuclear energy to contribute to Japan's CO_2 reduction through a wide range of applications including hydrogen production, high efficiency power generation and heat supply as discussed in the foregoing sections. As shown in Fig. 8, the total potential CO_2 reduction is 15%, a significant share of Japan`s 80% CO_2 reduction goal in 2050.

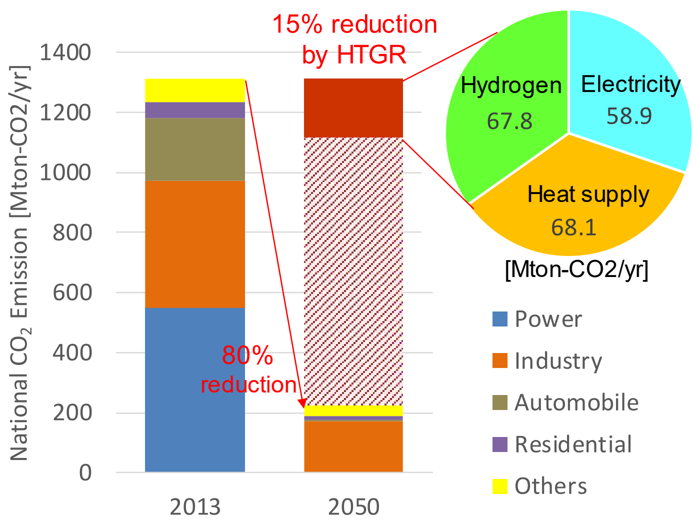

FIG. 8. CO_2 reduction contribution by the HTGR (15%) with additional contributions to be made by both renewable energy and such other technologies as carbon capture and efficiency improvement.

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GEN ENERGIJA ENHANCING EFFICIENCY OF NPP KRŠKO WITH COGENERATION AND OPTIMIZATION OF HYDRO POWER PLANT OPERATION IN COMBINATION WITH NPP COOLING CELLS

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Abstract

Climate change and environmental commitments force the need to make improvements in energy systems. Improving efficiency is one way to contribute to the goal of reducing impact on the environment. Gen energija, the owner of the Slovenian part of the nuclear power plant (NPP) in Krško, is constantly trying to improve operation of its generating units. GEN carried out a feasibility study on cogeneration in NPP Krško. The study analysed potentials of heat utilisation, potential customers and heat demand in the area. Another example of efficiency enhancement is managing the hydro power plants on Sava River in synergy with NPP Krško. With coordinated operation of hydropower plants on Sava River and NPP Krško cooling towers, noticeable energy savings were achieved.

1. INTRODUCTION

In Slovenia, as well as in the European Union and other countries around the world, the production of electrical energy in a sustainable way is of increasing importance. GEN energija produces more than 99% of electricity by a nuclear power plant (NPP) and hydro power plants (HPP). The annual output accounts for around 30% of the country's total electricity production. In terms of CO_2 emissions, the GEN Group's production units contribute significantly towards the relatively low average level of the country carbon footprint (see Fig. 1).

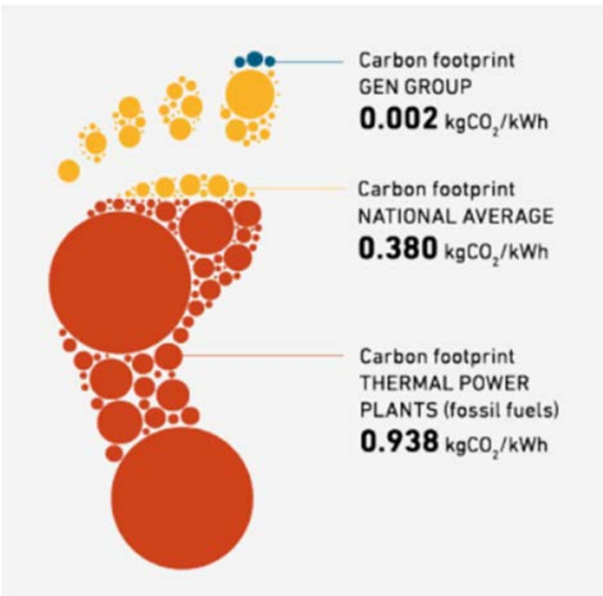

FIG. 1. Carbon footprint [1].

Regardless of the very low carbon footprint, GEN energija is still trying to improve the efficiency of its plants, e.g. by introducing cogeneration in the NPP and optimizing the production of the HPPs and NPP that are on the same river.

GEN carried out a feasibility study on cogeneration in NPP Krško [2] which was later reviewed and updated [3]. Approximately one third of the generated thermal energy in the core is converted into the electrical energy. This is due to the thermodynamic cycle process which is constrained by lower and higher temperatures. However, the generated heat can be used not only for electrical purposes, but also for other purposes (i.e. district heating, district cooling, agriculture, industrial steam, etc.). In this sense the electrical efficiency cannot be increased, but the total efficiency of the plant can be increased.

The second example of an efficiency enhancement is by managing the hydro power plants on the Sava River in synergy with NPP Krško. Operation of hydro power plans (upstream from NPP Krško) is done in a way that avoids or at least postulates the running of cooling towers in NPP Krško.

2. COGENERATION IN NPP KRŠKO

NPP Krško is a Generation II pressurized water reactor (PWR) power plant with two loops. It has a thermal power of 2000 MW_{th} and electrical power of 700 MW_e. The plant was designed by Westinghouse and started operation in 1983. Its design lifetime is 40 years; however, it is in the process of extending its lifetime by an additional 20 years. The original power plant design was upgraded with systems that increase both safety and power. A safety upgrade as a post-Fukushima modification is in its final phase of implementation. The plant is located on the northern bank of the Sava River, near the town of Krško. It is cooled with once through cooling in combination with cooling cells which come in operation in dry and hot summer periods.

Nuclear cogeneration has been successfully implemented in various NPPs around the world. However, its deployment in NPPs is more an exception than a rule. Recently, nuclear cogeneration is becoming increasingly interesting and recognizable as the waste heat from the nuclear fleet represents an enormous, environmentally friendly and CO_2 free source of energy that could help humanity in mitigating climate change.

GEN energija completed its first feasibility study on cogeneration back in 2007 when the possibility of waste heat utilization for the new planned NPP Krško 2 (JEK 2) was analysed [4]. However, since the project was postponed in the future, a similar study was performed for the existing NPP Krško. A comprehensive analysis and comparison of several heat sources (e.g. nuclear, biomass, geothermal, gas, etc.) that could potentially be used for the district heating was done. The study included an estimation of the range of potential consumers in the nearby region, an estimation of the annual heat demand and the analysis of environmental impact and economic feasibility of different scenarios [5]. The most promising utilization of heat from the NPP were [2] [3]:

- District heating;
- Use of steam in industry.

Additional examples of heat utilization could also be in district cooling and use of heat in agriculture. However, the study showed that such systems are not economically feasible. Similar information to that presented in this section (regarding cogeneration in Krško NPP) will be published in the forthcoming NEA study [6].

2.1. District heating

In the world, as well as in Slovenia, district heating systems are increasingly common. District heating by means of combined heat and power (CHP) production can significantly reduce the environmental impact, but also increase the energy efficiency of a power plant. However, not many NPPs are connected to the district heating systems.

2.1.1. Heating needs in local area

NPP Krško lies next to the towns Krško and Brežice with total population of around 14 500 people. The area has a diverse heating source structure. The current systems are mainly based on:

— Biomass;
— Natural gas;
— Oil;
— Electricity–heat pumps.

In order to analyse the technical and economical feasibility of the project, a survey for potential heat needs was performed.

Four main groups of potential district heat consumers have been identified:

— Consumers connected to major common boiler houses;
— Public buildings;
— Major individual boiler houses;
— Other consumers (e.g. detached houses, cafes, business premises, and other potential consumers not classified in one of the above given consumer groups).

The total heat demand was estimated based on the following assumptions:

— All public buildings will connect to the district heating;
— 75% of the rest of buildings will connect to the district heating;
— Energy efficiency measures will also take place in the near future;
— Population will slightly increase in the future.

Taking into account the above assumptions and considering an additional need of 20 000 MWh/year for sanitary water, the total annual heat demand could be approximately 123 000 MWh/year.

The total installed power of the heat source was defined on the basis of the conservatively taken concurrency factor of 0.72, the assessed power required for hot sanitary water preparation, and power required for covering heat losses in the district heating system (estimated heat losses amount to 11 600 MWh/year); it amounts to approximately 70 MW_{th}.

2.1.2. District heating system characteristics

The district heating system of the Krško and Brežice area has been designed for the areas populated by approximately 14 500 people. In the Krško area there are around 8000 and in the Brežice area around 6500 residents. The Nuclear Power Plant Krško (NPP KRŠKO), representing a potential and adequate heat source for the district heating system supply, is located several kilometres from the consumers. In the section where the pipeline diameter is the largest, the length of the main hot water line running towards Krško amounts to approximately 2.3 km. The total length of all branches within the Krško distribution system (Fig. 2) amounts to approximately 44 km. The length of the route extending from the heat source to the most distant consumer in the Krško region amounts to approximately 7 km. Compared to Krško, Brežice is a bit further from the heat source. In the section where the pipeline diameter is the largest, the length of the main hot water line running towards Brežice (Fig. 3) amounts to approximately 7.8 km while the total length of all branches within the Brežice distribution system amounts to approximately 45 km. The length of the route extending from the heat source (NPP Krško) to the most distant consumer in Brežice is approximately 12 km.

Two different temperature regimes were analysed, 90°C/60°C and 120°C/60°C. The analysis showed that the regime of 120°C/60°C is more appropriate, mainly due to the smaller pipes (lower costs) needed for the same amount of transferred heat energy.

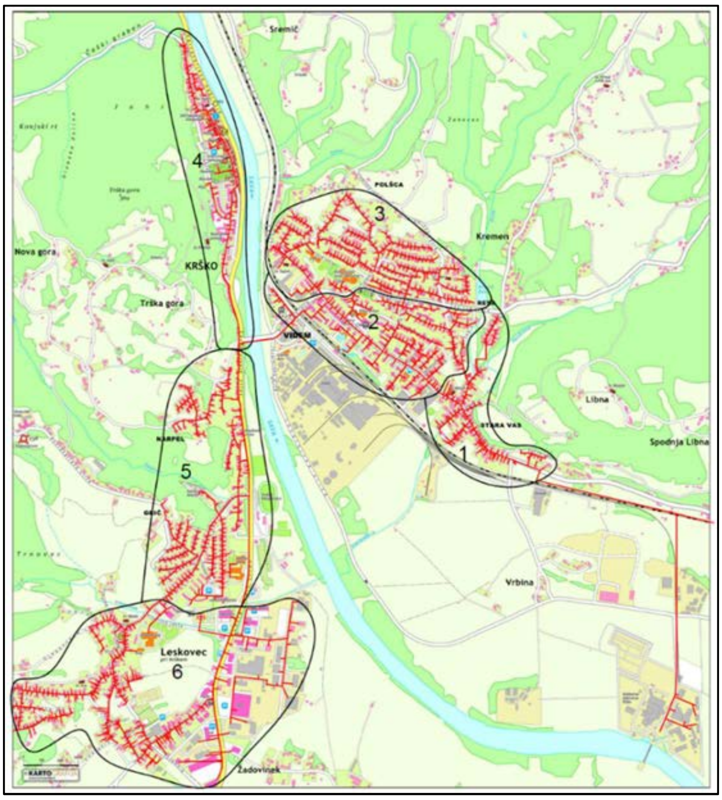

FIG. 2. District heating system in Krško [2].

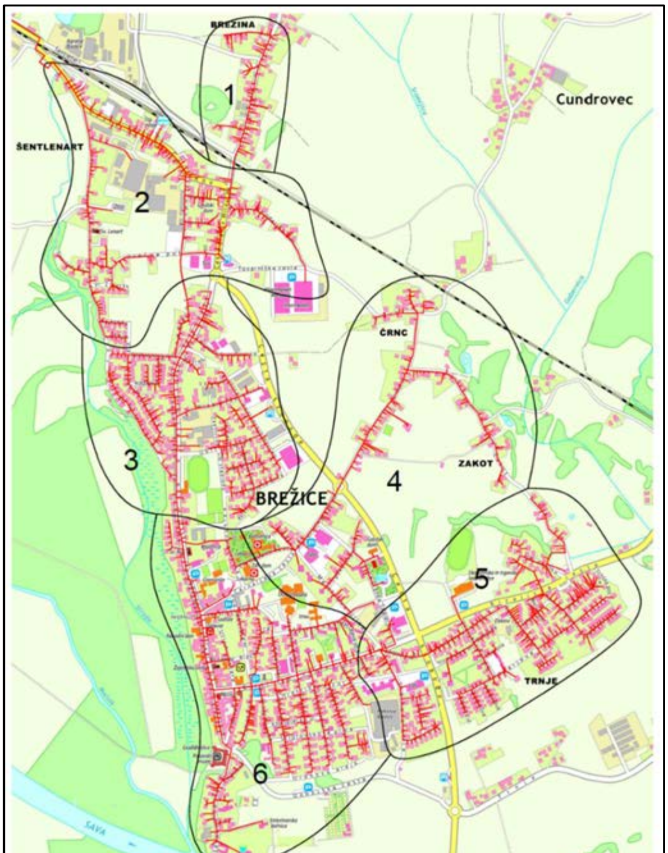

FIG. 3. District heating system in Brežice [2].

2.1.3. Possible heat sources in NPP Krško for the district heating system

In the study [2], several alternative heat generating sources (e.g. NPP cogeneration, heat pumps on tertiary system, wood, gas, etc.) for district heating supply were analysed. The analysis showed that the most prominent solution is heat utilization from NPP KRŠKO. With regard to the heat consumption, the district heating of Krško and Brežice area is a relatively small system, yet with a rather large branched distribution system. A favourable price of heat from NPP KRŠKO represents one of the main advantages of the planned district heating system.

The heat source power required for heating the area of Krško and Brežice was estimated to approximately 70 MW. The average annual load of the district heating system amounts to 18.5 MW. The heat sources, which can ensure a sufficient heat supply for the district heating or other purposes from NPP KRŠKO, are:

- Steam extraction from the secondary circuit;
- Waste heat from the tertiary circuit at condenser outlet.

The first case involves heat extraction from the turbine steam on account of a somewhat reduced electricity generation. The second case involves utilization of the heat potential of low temperature water leaving the system after the condenser. The utilization of waste heat from the tertiary circuit at NPP KRŠKO's condenser outlet was identified as one of the most attractive technical solutions of the heat source supplying the district heating system since it does not interfere on the operation of NPP KRŠKO. A combination of two stage heat pumps as well as wood biomass boilers were foreseen to heat up the water to the higher temperatures. Based on a rough comparison of the results obtained in the basic study [2], [3], it has been concluded that the solution of heat pumps is economically less suitable than the solution of steam extraction from NPP KRŠKO.

In the secondary circuit of NPP KRŠKO, five extraction points have been identified as potential connection points (Fig. 4):

- Extraction 1: Replacement of high pressure turbine (planned modification in NPP KRŠKO).
- Extraction 2: Extraction point between the moisture separator reheater (MSR) and low pressure turbine.
- Extraction 3: Steam extraction from an existing high pressure turbine line (EX system).
- Extraction 4: Steam extraction on the cross connection of the steam lines for the regenerative heaters 2A and 2B.
- Extraction 5: Steam extraction from the low pressure turbine.

Steam extraction in NPP KRŠKO represents the most suitable and verified heat source of the planned district heating system (Fig. 4). The most appropriate connection point would be the Extraction 4 (9.6 bar, 178°C) where reduction of electrical energy due to the less available steam in turbines is the lowest. It is positioned at the outlet of the steam pipe from the high pressure turbine on the so called cross-connection before entering into the MSR. The maximal steam extraction at this point required for the district heating system amounts to 128 t/h (at 70 MW of the source thermal power, it amounts to 112 t/h), and the average one to 29.5 t/h. The required annual quantity of steam at the extraction point corresponding to approximately 123 000 MWh/year of the supplied heat amounts to 215 129 t. Electrical power output reduction at 70 MW thermal power of the source amounts to 14.9 MW_e, while the average reduction at 18.5 MW thermal power amounts to 3.93 MW_e. Fig. 4 shows different analysed heat sources.

Besides the extractions on the high pressure part of the turbine, a possibility of steam extraction from the low pressure part of the turbine was analysed as well. At this stage, and on the basis of available data, it was concluded that this possibility is less favourable.

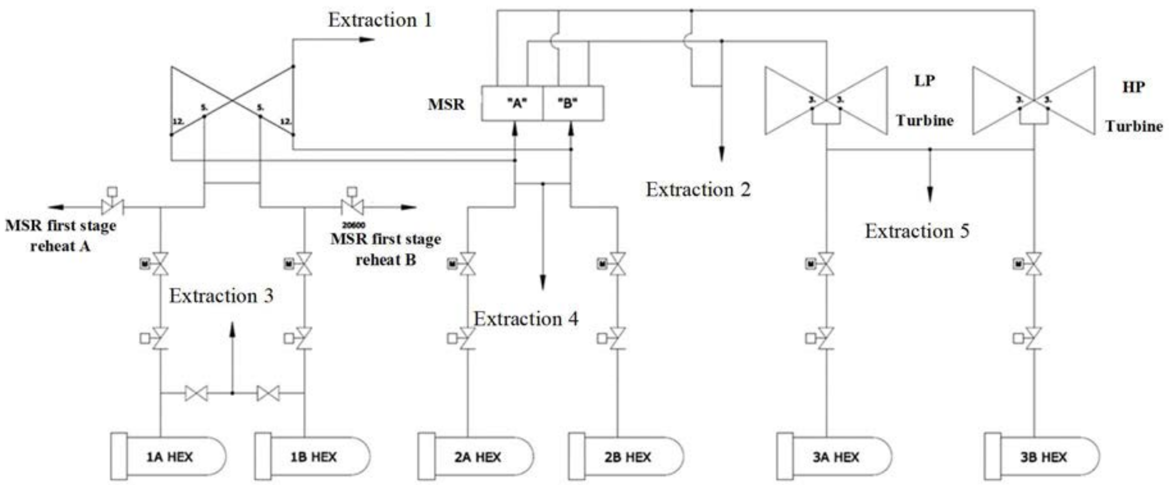

FIG. 4. Different extraction points [2].

District heating of the Krško and Brežice area is reasonable only in the case of the nuclear power plant lifetime prolongation. After the year 2043 the heat source in NPP KRŠKO would be substituted by the heat generated in the planned JEK 2.

2.1.4. Backup systems for heat supply

Several options for backup systems were also considered to ensure a replacement of the main heat source in the district heating system in case of planned/unplanned shutdown of NPP KRŠKO:

— Existing boiler houses in Krško and Brežice (over 40 MW heat) — Backup 1;
— Existing Gas Power Plant Brestanica (TEB) — Backup 2;
— Existing heat system in the factory Vipap (66 MW) — Backup 3;
— Gas boiler (40 MW) — Backup 4;
— Electric heater (40 MW) — Backup 5.

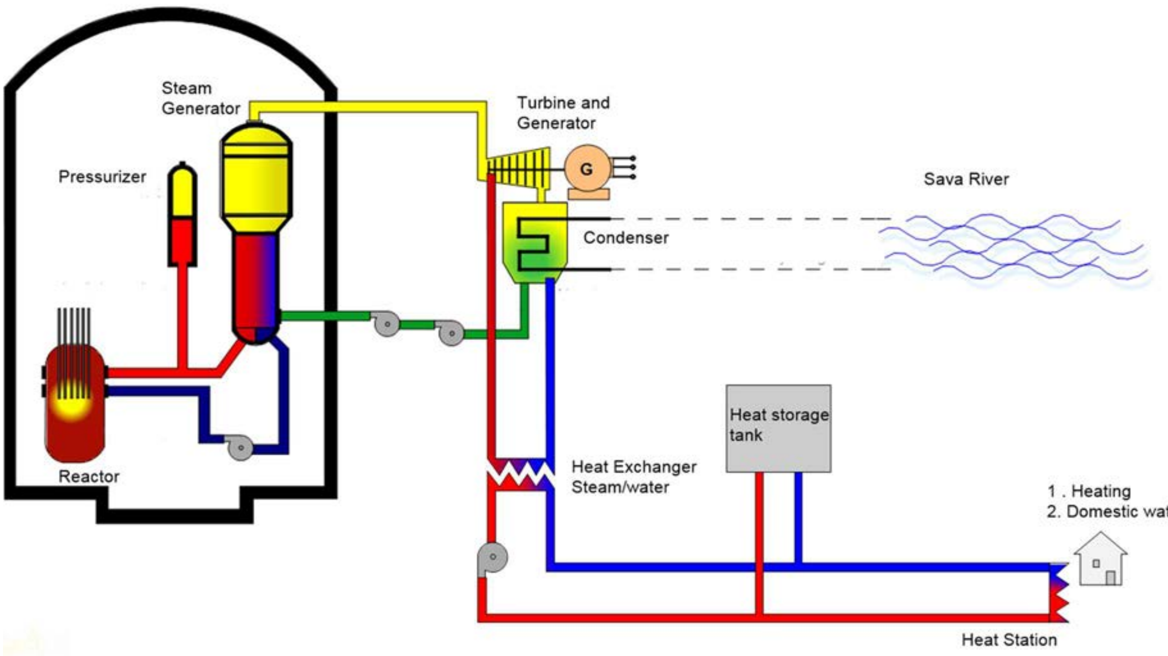

FIG. 5. Schematic positioning of heat storage tank [2].

The analysis showed that the most appropriate solution are the existing boiler houses in Krško and Brežice which shall be primarily used as a replacement of the heat source in NPP KRŠKO. These boiler houses can ensure 40 MW_{th} of thermal power. In order to meet the maximal demand of up to 70 MW_{th} an additional gas boiler house of 30 MW_{th} is foreseen. A heat storage tank of approximately 260 MWh_{th} capacity and a volume of 6900 m^3 is foreseen as well (Fig. 5). In terms of providing a continuous transition from the basic source to the replacement heat sources a heat storage tank might not be necessary, yet it enables a more optimal operation in terms of the heat and electricity generation, it also balances oscillations and transients.

2.2. Steam production for industry

Potential NPP KRŠKO industrial steam consumers are the nearby companies Vipap and Krka. Vipap is the largest paper production factory in Slovenia, meanwhile Krka is an international generic pharmaceutical company. Both companies use their own boilers for steam production. Krka uses gas whereas Vipap uses coal, biomass or gas. Due to the old technology as well as environmental limitations regarding coal fired boilers, Vipap will no longer be able to produce the steam by means of obsolescent boilers. The production of steam from NPP KRŠKO presents a good alternative to currently used or other available steam sources. The price of steam produced in NPP KRŠKO would be very competitive to all steam source systems in nearby industrial facilities as well as to any other alternative solutions. The steam capacity requirements are as follows:

- Steam of 12 bar (abs) pressure, 188°C temperature for Krka: 16 t/h;
- Steam of 4.6 bar (abs) pressure, 190°C temperature for Vipap and Krka: 60 t/h.

As mentioned previous, potential industrial steam consumers are the nearby companies Vipap and Krka. The companies have different process requirements for steam as shown in Table 1.

TABLE 1. STEAM CAPACITY REQUIREMENTS IN NEARBY INDUSTRIAL FACILITIES

INDUSTRIAL CONSUMER(S)	PRESSURE (bar)	TEMPERATURE (°C)	STEAM FLOW (t/h)
Krka	12	188	16
Vipap and Krka	4.6	190	60

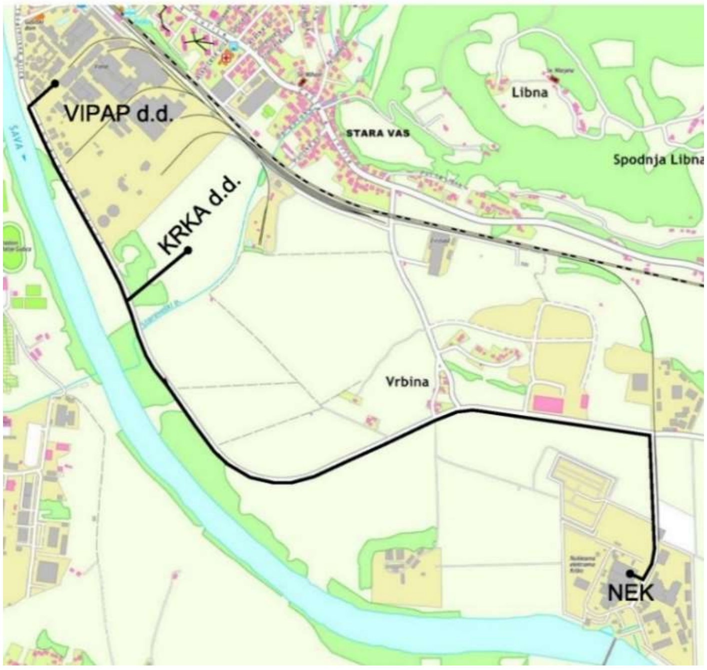

FIG. 6. A schematic display of the foreseen steam distribution system for industrial consumers Vipap and Krka [2].

In line with different requirements for steam parameters, two separate distribution systems from NPP KRŠKO are foreseen. The distance between the steam generators in NPP KRŠKO and both industrial consumers (Vipap and Krka) is approximately 3.5 km. The aboveground pipelines are routed as shown in Fig. 6.

2.2.1. Distribution of 12 bar (abs), 188°C steam for Krka

In NPP KRŠKO, a new industrial steam (steam–steam) generator of 12 MW thermal power shall be installed. The heat source applied shall be steam from the Extraction point 3 (Fig. 4) with a capacity of 17.5 t/h. Steam generated in the steam generator shall then be distributed along a DN 150 steam pipeline to the consumer Krka. Subcooled condensate of around 60°C temperature shall be supplied into a condensate tank located in close vicinity to the consumer, and further on, by feed pumps, via a DN 50 pipeline back to the industrial steam generator in NPP KRŠKO. It is assumed that the consumer would take care for replacement and suitable quality of the lost medium. At the consumers location, steam shall be compressed to a required pressure of 12 bar (abs). The circulating pump power shall be 15 kW. The anticipated annual consumption of steam at a higher pressure covering the needs of the Krka plant in the final construction phase shall achieve 131 000 t.

TABLE 2: CHARACTERISTICS OF 12 BAR DISTRIBUTION TO KRKA

PARAMETER	VALUE
Pressure	12 bar (abs)
Temperature	188°C
Power of industrial steam generator	12 MW
Capacity	17.5 t/h
Heat source	Extraction 3
Temperature of condensate	60°C
Circulating pump power	15 kW
Estimated annual consumption	131 000 t

2.2.2. Distribution of 4.6 bar (abs), 190°C steam for Vipap and Krka

In NPP KRŠKO, an additional new industrial steam (steam–steam) generator of 44 MW thermal power shall be installed. The heat source applied shall be steam from the Extraction point 3 (Fig. 4), in the capacity of 67 t/h. Steam generated in this steam generator shall be then distributed along a DN 450 steam line to the consumers Vipap and Krka. The subcooled condensate of around 60°C shall be supplied into (a) condensate tank(s) located in close vicinity to the consumers and further on, by feed pumps, via a DN 100 pipeline back to the industrial steam generator in NPP KRŠKO. It is assumed that the consumer would take care for replacement and suitable quality of the lost medium. At the individual consumer’s location, steam shall be compressed to a required pressure of 4.6 or 4 bar (abs), respectively. The circulating pump power shall be 35 kW. The anticipated annual consumption of steam at a lower pressure covering the needs of the Krka and Vipap plants in the final construction phase shall achieve 510 000 t.

In case of unavailability of the basic source (e.g. at a forced outage of NPP KRŠKO or during NPP KRŠKO overhaul) the potential industrial steam consumers Vipap and Krka will use their own capacities as replacement sources.

TABLE 3: CHARACTERISTICS OF 12 BAR DISTRIBUTION TO KRKA AND VIPAP

PARAMETER	VALUE
Pressure	4.6 bar (abs)
Temperature	190°C
Power of industrial steam generator	44 MW
Capacity	67 t/h
Heat source	Extraction 3
Temperature of condensate	60°C
Circulating pump power	35 kW
Estimated annual consumption	510 000 t

2.3. Economic analysis

Three different variants were analysed. Variant 1 and 2 are two possible alternatives for the district heating system, whereas Variant 3 is a distribution system for industrial steam supply.

- Variant 1: steam extraction from the secondary circuit;
- Variant 2: waste heat from the tertiary circuit with reheating provided by heat pumps and biomass boilers;
- Variant 3: industrial steam supply.

The economic analysis was based on the provisions of the Energy Act and the Regulation on the Formation of Prices for Production and Distribution of Steam and Hot Water in the District Heating System for Tariff Users (*Uredba o oblikovanju cen proizvodnje in distribucije pare in tople vode za namene daljinskega ogrevanja za tarifne odjemalce*, 2014) [7]. For tariff users the price of heat is regulated by the Energy Act EZ-1 [8] and Regulation on the Formation of Prices for Production and Distribution of Steam and Hot Water in the District Heating System for Tariff Users. According to this Regulation the price is defined on the level of justified expenses. The price may also include the profit which is however intended only for legal and statutory reserves of the distributor and is therefore not available for payments to the owners (return on owner equity).

Different technologies for heating are used in the area of Krško and Brežice. Based on the available data from Local Energy Concepts in the area of Krško predominantly used technologies are based on natural gas (45%), followed by solid fuels (34%) and oil (18%). In the area of Brežice the prevailing technology is based on oil (38%), followed by solid fuel (36%) and lastly natural gas (23%). The remaining 3% cover the use of other technologies mainly based on electricity.

The most competitive and attractive variant for district heating is district heating system (DH) from NPP KRŠKO (Variant 1) (Fig. 7). This assumption was made considering the existing system based on solid fuels systems, which have already been depreciated.

Regarding analysis made and an average Slovenian price of heat around 65.5 EUR/MWh, it is clear that the price of heat in the Krško–Brežice distribution system would be favourable.

Even though the selling price of heat is regulated by law and does not allow to make profit for the investor, this does not mean that the investment in general does not generate financial benefits. In the case of regulated heat prices the majority of financial benefits are for the consumers, whereas environmental as well as social benefits are in favour for the community.

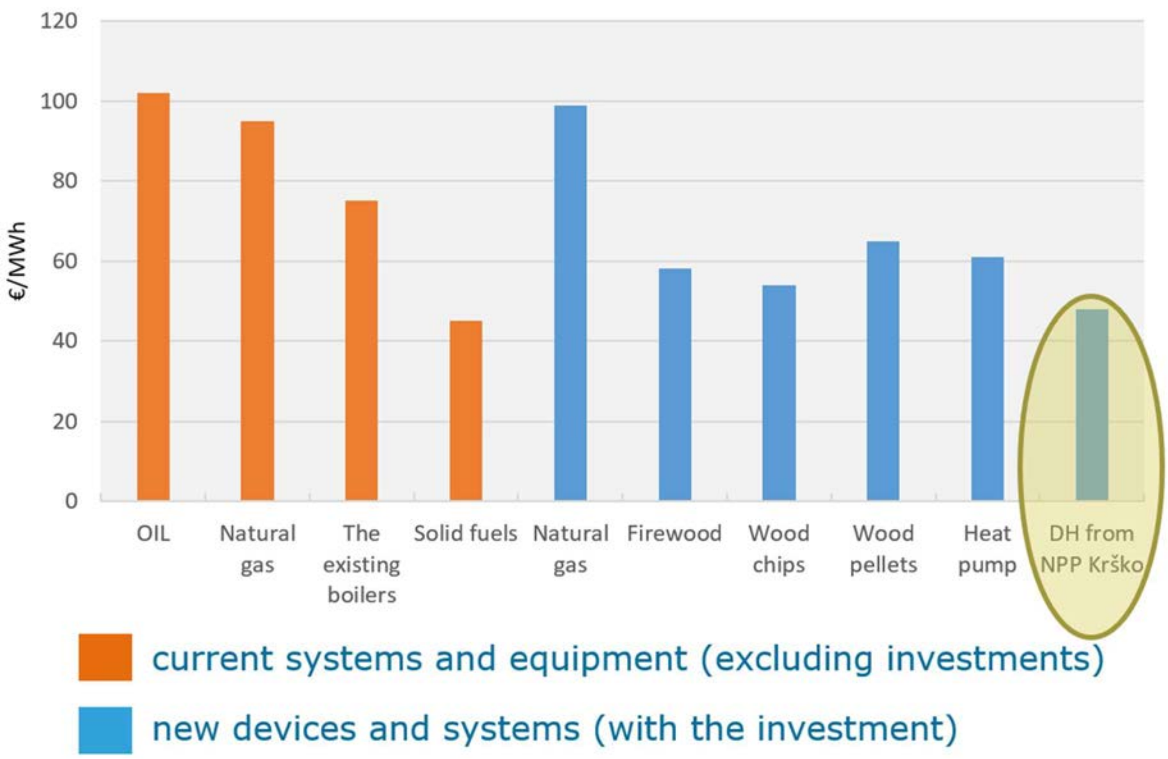

FIG. 7. Prices for individual heating systems in the area of Krško and Brežice compared to the district heating system from NPP KRŠKO (Variant 1) [5].

The systems for steam supply to the industrial facilities in the vicinity of NPP KRŠKO were also analysed. The selling price of steam for industrial users is not regulated as in the case for district heating but is a matter of negotiation between the seller and the buyer. In any case it should be a win–win situation. Thus, from the investor point of view, supplying steam to the industrial facilities could be the main reason to invest its own capital into the project (district heating and industrial steam).

3. MANAGING HYDRO POWER PLANTS ON SAVA RIVER IN SYNERGY WITH NUCLEAR POWER PLANT KRŠKO

3.1. Control centre in GEN energija [1]

The GEN energija Control Centre ensures optimal production of electricity across the Group's power plants and optimizes operating costs for the entire Group.

GEN Control Centre is the central hub for steering the operation of the Group's power generation facilities under normal as well as emergency operating conditions.

GEN Control Centre's main tasks are to:

- ensure maximum utilization of all available production units;
- coordinate and synchronize the operation of production units;
- minimize the impacts of unforeseen events.

GEN Control Centre supervises the production process at power plants: Brežice HPP, Moste HPP, Mavčiče HPP, Medvode HPP, Vrhovo HPP, Brestanica Thermal Power Plant and Krško Nuclear Power Plant that are controlled by subsidiaries (Fig. 8). In 2016 GEN Control Centre took over direct remote control of the hydroelectric power plants on the lower Sava River (Boštanj HPP, Arto–Blanca HPP, Krško HPP) that are upstream of NPP Krško. To interact and collaborate in the electricity market, the production units are brought together under the GEN balancing subgroup. Optimized operating timetables are designed (day ahead, intraday) for this balancing subgroup. Production is constantly being monitored for deviations from the timetables, and if any deviation is observed, appropriate measures are taken. By doing so, it is possible to fully utilize all the synergies arising from the specifications of individual production units across the entire GEN energija.

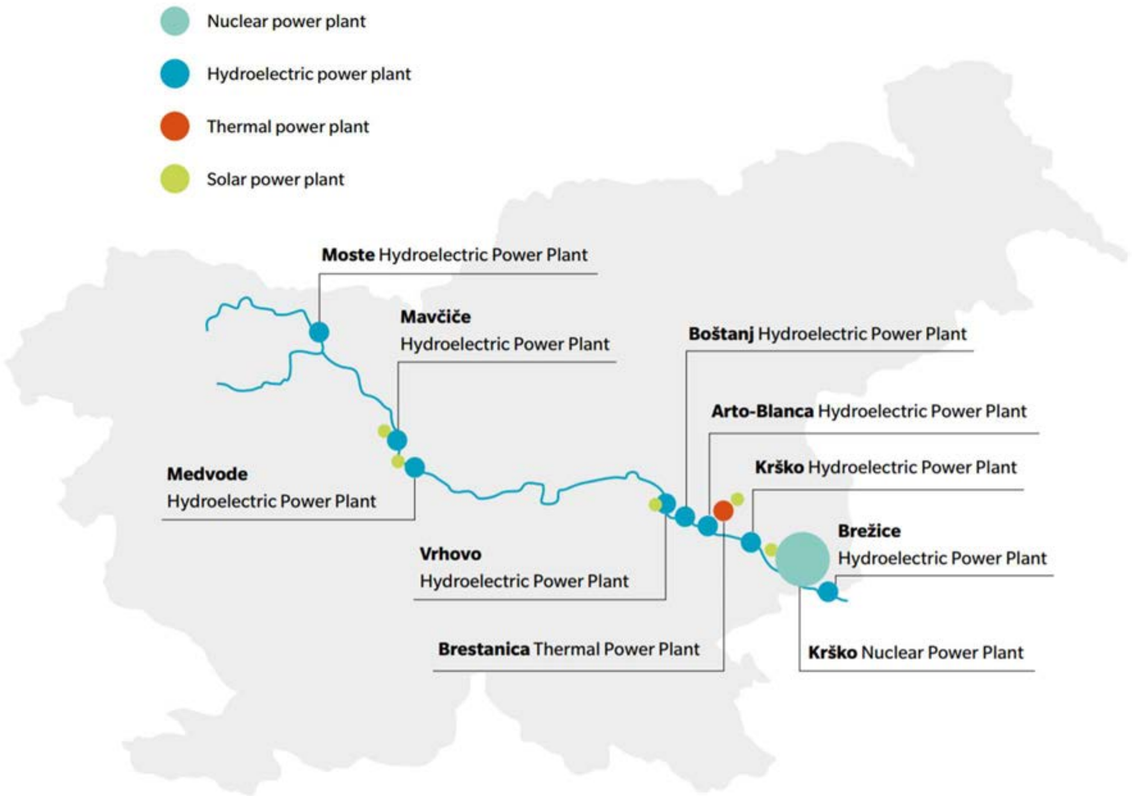

FIG. 8 The GEN Group's electricity generation units [9].

3.2. Control of hydro power plants on Sava River to optimize the usage of cooling towers on Nuclear Power Plant Krško

As described in Section 2 NPP Krško is cooled with once trough cooling and additional with cooling cells. The latter are turned on only when the river is heated by the NPP for more than 3°C or when the water is too dirty and there is a problem with clogging of travelling screens. When the NPP is running one part of the circulating water that cools the condenser can be recirculated through cooling towers in order to reduce the heat load to the river. Two cooling tower pumps with a power of 2000 kW [10] each can direct 15 m^3/s of the cooling flow to the towers. The system is built in a way that enables operation of one or two pumps in different combinations with cooling towers and fans. This enables better adaptation to hydrometeorological needs and easy service of cooling towers.

Although cooling cells enable NPP Krško to run in more extreme conditions, they consume in combination with cooling tower pumps a lot of energy. Also, the water that has been cooled by cooling towers is not as cold as the Sava River, which means that the efficiency of the plant is lower.

In order to avoid or at least postpone the running of cooling towers by NPP Krško, Control Centre in GEN energija tries to control the operation of hydro power plants in a way that avoids or at least postulates the running of cooling towers in NPP Krško. The hydro plants that can be used for control and optimization are located upstream from NPP Krško (HPP Vrhovo, HPP Boštanj, HPP Arto–Blanca and HPP Krško). Energy savings are not negligible. It has been assessed that up to 26 MW can be 'saved' (for a short time). Generally, savings of around 2–3 MW over a few days span (up to a week) are recorded. To compare, the controlled hydro plants (mentioned above) have a total average output of 60 MW [11].

The accumulation of hydro power plants on Sava River are small (Vrhovo, HPP Boštanj, HPP Arto–Blanca and HPP Krško have a total of (5 million m^3) [11] and represent an energy reserve that can be converted into electricity within a day when operating on full power (at average flow of the Sava River).

Nevertheless, it is enough to additionally feed the river flow before the Krško NPP and postulating the start of cooling towers.

When the water flow falls too much and cooling towers have to be turned on, GEN energija accumulates and discharges water from the lakes in such a way that only one cooling tower pump is actuated for as long as possible. If water flow still decreases, the second cooling tower pump is turned on. With one operating pump 75% of minimal flow is needed and with two operating pumps 50% of the minimal flow is needed (100% presents minimal flow for only once through cooling). If water flow is more than 50% and less 75% (or more than 75% and less than 100% for one pump) accumulation lakes can be filled again with the extra flow.

An important factor for good optimization is monitoring of meteorology. If, for instance, rain is foreseen after a period of drought, accumulation lakes can be totally emptied. The second important factor is the price of electricity on the market. When the price of electricity is low (for instance on weekends), cooling towers on NPP Krško operate and accumulation lakes are being filled; when the prices are high, cooling towers are turned off and accumulation from lakes is used.

4. CONCLUSION

For GEN energija, sustainable energy source has big importance which can be seen in its electricity production that is 99% generated from sustainable and renewable low carbon sources. GEN energija's main sources of energy are Nuclear Power Plant Krško, hydro power plants (HPP) on the Sava River and also some solar power. In order to enhance efficiency of its production, new studies such as a feasibility study on cogeneration in NPP Krško optimization were made. District heating and steam for industry show a lot of potential. District heating brings obvious financial benefits for users and also provides a significant contribution to the cleaner and friendlier environment with less CO_2 and other emissions. Also, steam for industrial needs has very low costs, which is a great opportunity for GEN energija and for the industry, which could become more competitive.

Another example of enhancing production is by control of hydro power plant on Sava River to optimize the usage of cooling towers on NPP Krško. In order to avoid or at least postulate the running of cooling towers by NPP Krško, GEN energija tries to control the operation of Hydro power plans in a way that avoids or at least postulates the running of cooling towers in NPP Krško.

By optimization of production, significant economical as well environmental benefits are seen.

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ANALYSIS OF OFFERING CONTINUOUS LEVEL OF POWER TO ELECTRICITY MARKET FROM WIND PLANTS AND BACK-UP PLANT — WHAT FLEXIBILITY SHOULD HAVE THE NPP?

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Abstract

Wind power varies over time and variations occur on all time scales. Understanding these variations and their predictability is of key importance for the integration and optimal utilization of wind in the power system. Due to the variability and uncertainty, wind plants cannot offer a continuous level of power to electricity market.

The main motivation for this analysis is to investigate possibilities to participate in the electricity market by offering continuous guaranteed power from wind plants by a backup plant.

If NPPs and RESs want to become 'friends', it is necessary to determine which minimum characteristics of feasibility the NPPs should have.

A model of electricity production from wind farms and a backup plant was developed based on real hourly and minute by minute electricity production from wind plants. For the calculation, the following parameters are necessary: ramp up and down rate, time of start time reduction, fuel mass flow during start, electricity production during start, variable cost of the startup process, cost and charges for lifetime consumption for each start and start type, remuneration during startup time regarding expected or unexpected starts and the cost and revenue for balancing energy.

In the analysis, because all needed parameters for the NPP are not known, a backup plant was selected to be a Combined Cycle Gas Turbine (CCGT) plant with input data and all characteristics on hourly and minute by minute timescales.

Hourly analysis showed that there was no problem with delivery of the defined power, but the minute by minute resolution analysis showed that the backup plant could not always cover rapid changes in response to actual changes in wind power production.

The analysis has shown that with the same wind variability with shorter time resolution, realistic technical limitations of the backup power plant come to light, especially in terms of output speeds and output power drops. The one minute resolution results in significantly higher requirements on the backup facility, which confirms the need to adjust the time resolution of input data based on stochastic modelling of wind power plants, and time resolution (intervals) of optimization.

The paper describes problem that was analysed in the study [15] *Analysis of the possibilities of work and assessment of the corresponding costs of the new CCGT type 3 + 1 plant in Croatian Power System.* Descriptions of models, scenarios, results and discussion are taken over from that study.[16]

From the results of the analysis, it is possible to determine which minimum characteristics of flexibility the NPP should have for a required production in conjunction with real wind power plants.

1. INTRODUCTION

Today's energy market is very uncertain and represents a great challenge for new investments. Investing in new sources of electricity represents a great challenge because of the high risk caused by uncertainty in the electricity market. The goal of each technology for electricity production is to cover a given load at any point of time, as well as cover the initial investment and earn a profit. In each moment in time, production and consumption need to be in balance and load to be covered by the production from various power sources. However, different energy sources have each have different issues.

Renewables represent a clean energy as they do not produce GHG emissions, but they have intermittent nature (wind and solar), their geographical distribution is typically uneven and the variability of renewables requires more operational flexibility to compensate fluctuations. This problem limits their participation in the energy market. The unpredictability of wind has a negative impact on participation of wind power plants in the market — a reliable constant amount of electricity is needed and the geographical distribution of wind power resources is typically uneven.

In today's market, with a huge share of renewables, some thermal and nuclear power plants struggle to create high enough profit to cover their investment cost because they are working at very low efficiency or they have must regularly start up and shut down, which increases operational costs, or do not operate at all. Frequent changes of the load cause changes in fuel consumption and emission levels. These changes in the operating modes have a significant effect on the O&M costs of conventional technologies, which in any case should not be ignored in long term planning and investment costs.

Nevertheless, energy strategies across Europe, and the world, encourage development of renewable technologies, and that dictates the development of the present energy industry. Our present lifestyle has a big impact on the future. The Kyoto Protocol and Paris Agreement are setting internationally binding emission reduction targets. The European Union aims for a low carbon economy — more climate friendly with less energy consumption. It includes the following important guidelines: (a) by 2050, reduction in emissions 80% below 1990 levels, (b) 40% emissions cut by 2030 and 60% by 2040, (c) contribution of all sectors, (d) the low carbon transition is feasible and affordable [1]. It encourages the development of the green energy sources with the goal of replacing the fossil fuel: wind, offshore wind, solar, hydroelectric, geothermal, tidal, wave, but most of them are variable and/or unpredictable. According to some studies [2,3], participation of wind in the market reduces the price of electricity and the attractiveness for the investment in natural gas power stations and in NPPs. On the other hand, having a huge share of stochastic renewables such as wind and solar creates a need in the system for balancing, especially when the produced electricity is lower than expected. This working regime forms peaks and gaps and solutions are energy storages, pumped hydro, OCGT and CCGT plants. The option considered in this paper is balancing the wind production with production from CCGT power plants (Fig. 1), taking into account production cost of three different models of CCGT — models with one, two and three gas turbines and one steam turbine. Previous work related to this theme [4, 5, 6] recognized great opportunities in this area by finding a set of optimal solutions in the moments when the load is variable, which makes CCGT one of the most flexible ways of balancing the unpredictable wind power.

[16] Problem and results are also described in paper: Ž. Tomšić, I. Rajšl, M. Filipović: Techno-Economic Analysis of Common Work of Wind and Combined Cycle Gas Turbine Power Plant by Offering Continuous Level of Power to Electricity Market; Journal of Sustainable Development of Energy, Water and Environment Systems; Volume 6, Issue 2, pp 276-290; DOI: http://dx.doi.org/10.13044/j.sdewes.d5.0186.

In many countries the price of the electricity produced from wind is determined by feed-in tariffs. The transmission system operator and the distribution system operator are obliged to connect the privileged producer on the network, to buy electricity from renewable energy sources and to apply the tariff system for the electricity produced in plants using renewable energy sources [8]. The increased share of the wind (as well as the other green energy sources) in the electricity market requires balancing if the conditions are not what were expected. This raises the problem of the day ahead forecasts which would significantly improve the position of the wind on the electricity market, more in [9]. Other options are required, considering that today is not possible to have a 100% predicted production of the wind at any point of time. This is important for peaks and gaps, especially when the wind production is less than anticipated. The priority is system stability — equality of production and consumption at any point of time. Some of the ways for providing peaking power are energy storage, pumped hydro, OCGT and CCGT. The option that is considered in this article is a CCGT–wind combination.

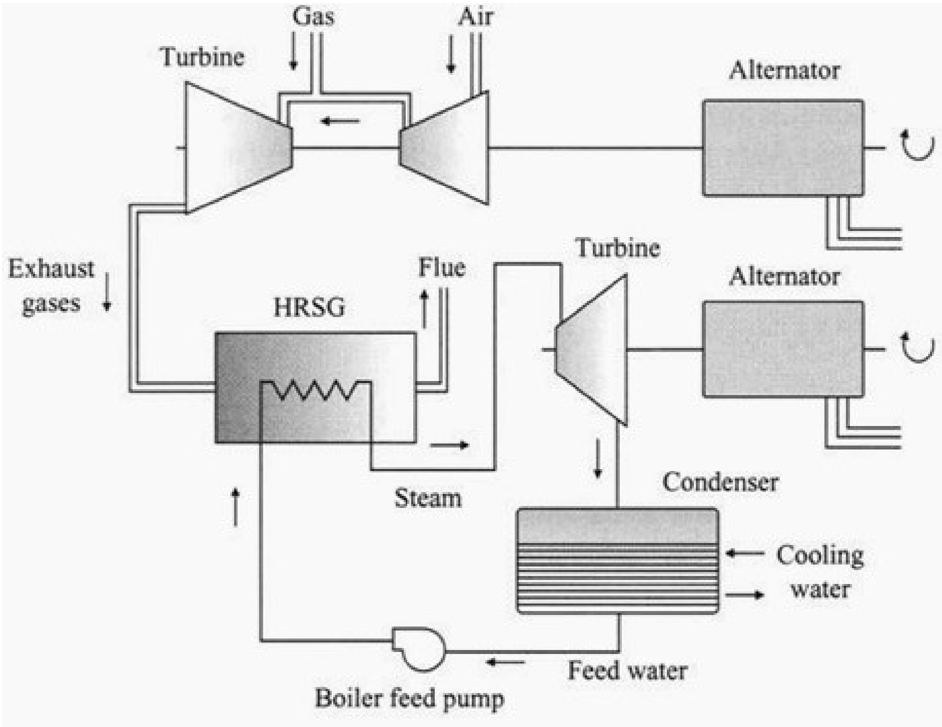

FIG. 1. CCGT plant principles [7].

Today's system and market do not allow CCGT to work in optimal conditions at nominal power. Frequent changes of the load consequently cause changes in fuel consumption and emission levels. These changes in the operating modes have a significant effect on the O&M costs of conventional technologies, which in any cause should not be ignored in long term planning and investment costs. Their impact is discussed in [10, 11]. It is important to take into account restrictions such as minimum power output, speed of rising and decreasing of the power, interdependence between starting time and previous operating condition of the plant and the all associated costs. Sustained levels of electricity on the market, created as a result of wind and CCGT, would allow wind to offer to the market a certain amount of energy with absolute certainty, and its variation in production would be covered by the CCGT. On the contrary, for wind power, the CCGT power plant implies an additional amount of revenue on the market where a conventional power plant can hardly penetrate and achieve sufficient passage to cover initial investment and generate profits. Gas power plants represent a cost competitive option from the perspective of investment in new power plants. CCGT power plants have significantly lower total cost of covering the peak load in the system compared to other power plants. According to [12], gas will play a key role in the transition process and the replacement of coal with gas can mean reduction in emissions with existing technologies until 2030 or 2035. Therefore, CCGT power plants have a certain advantage compared to other electricity generation technologies. CCGT use a gas turbine, the air–fuel mixture moves through the gas turbine, the HRSG (Heat Recovery Steam Generator) captures heat from the gas turbine and creates steam that is delivered to a steam turbine. Both the gas turbine and steam turbine convert mechanical energy to electricity. This mode of production, combined production, increases the production of electricity by up to 50% with the same fuel cost as traditional gas power plants. There are several ways of adjusting the performance of CCGT plants; for example, by changing the number of shafts, the production output of the plant can be optimized. By including more shafts, the investment costs increase; however, the flexibility, which is an extremely important factor for a CCGT power plant, enables monitoring of wind production and filling the set amount of gaps in the required amount of time. Many papers [4, 5, 6] focus on thermoeconomic optimization of CCGT, recognizing the great opportunities in this area for the competitiveness of CCGT power plants by finding a set of optimal solutions in moments when the load is variable. These specifications make CCGT one of the most flexible ways of balancing unpredictable wind power and provide great market opportunities for the mutual cooperation of wind and CCGT. CCGT plants can be constructed in single-shaft (Fig. 2) or multiple-shaft construction (Fig. 3 and Fig. 4). The single-shaft construction consists of one gas turbine, one steam turbine, one generator, and one HRSG, whereby the gas and steam turbines are connected to the same generator by one shaft.

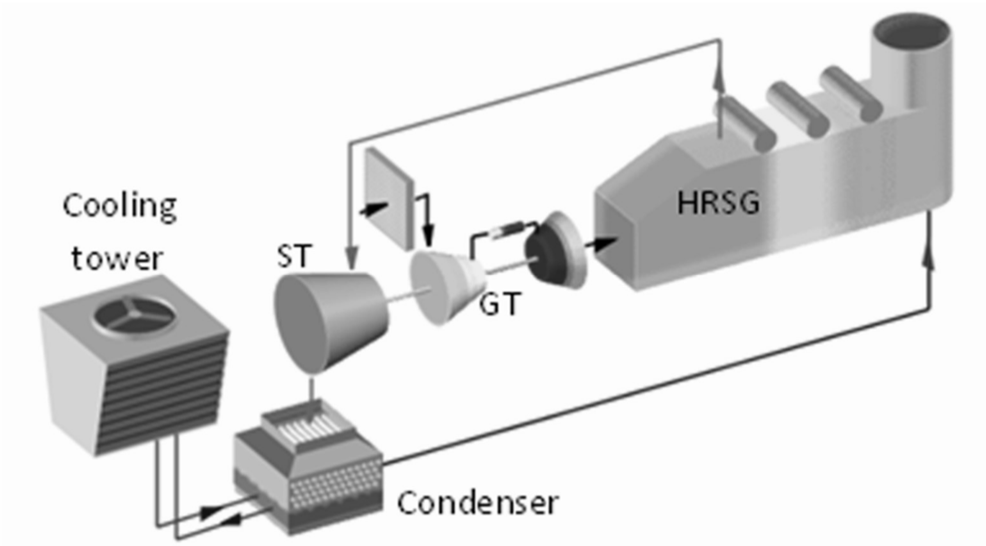

FIG. 2. Principle scheme of a single-shaft CCGT plant [13].

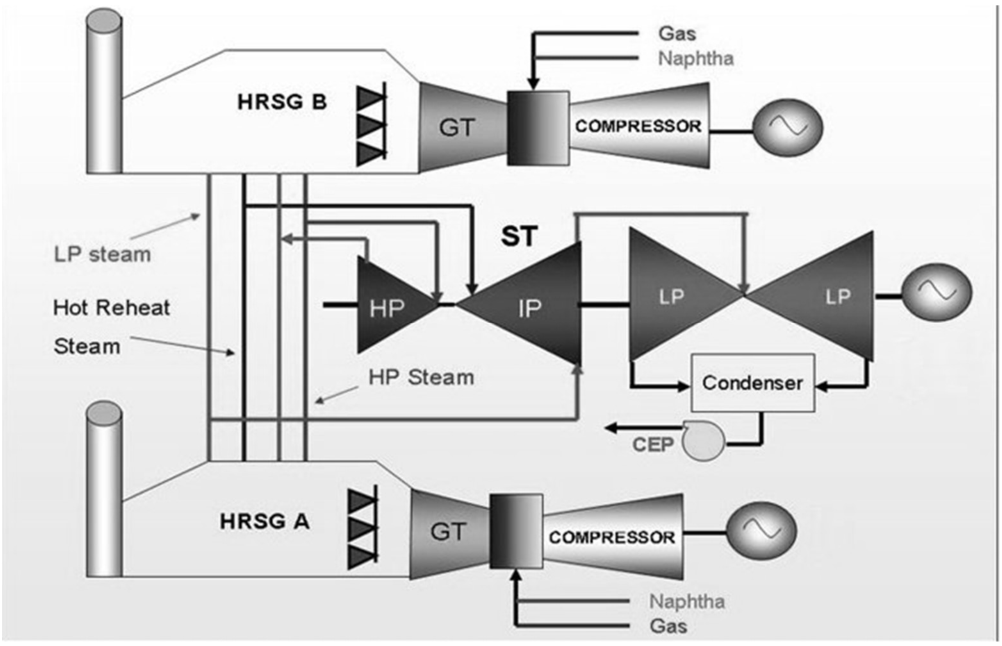

FIG. 3. Principle scheme of a two-shaft CCGT plant [14].

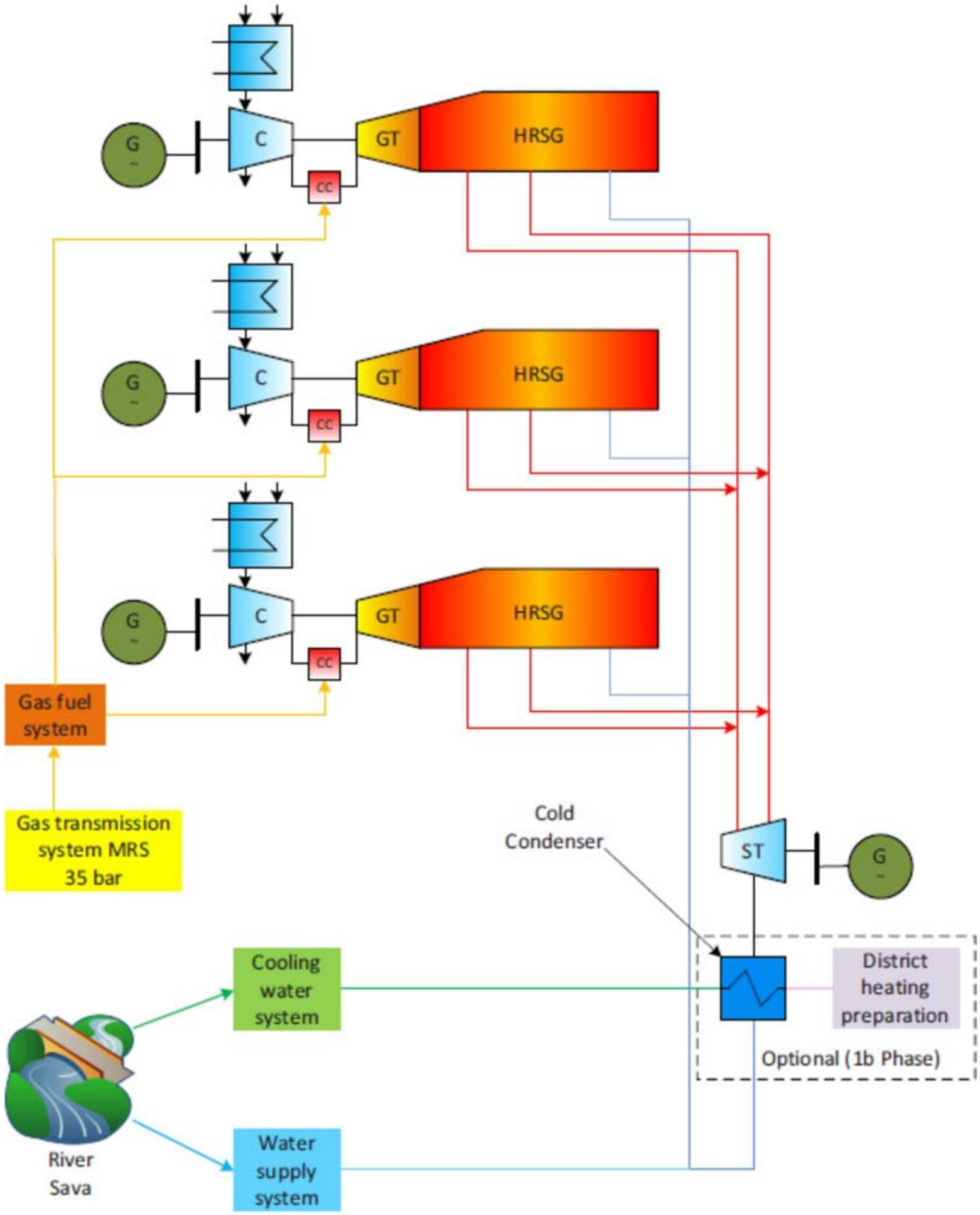

FIG. 4. Principle scheme of a three-shaft CCGT plant (3+1).

2. THE OUTLINE OF THE PROBLEM AND METHODOLOGY [15][17]

The objective of this work is to examine, on the basis of the model, technical and economic indicators of the CCGT power plant in functioning to balance or stabilize variable electricity production from wind.

From this work it can be seen what flexibility is required in a NPP for nuclear–renewable (wind) hybrid energy systems for decarbonized energy production and cogeneration.

For this purpose, a model in the programming tool PLEXOS was made.

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[17] The problem, models, scenarios, results and discussion are taken over from the study [15] *Analysis of the possibilities of work and assessment of the corresponding costs of the new CCGT type 3 + 1 plant in Croatian Power System.*

2.1. Technical aspects of CCGT power plant

The first part of the analysis is related to the technical ability (i.e. flexibility of CCGT power plants) for following variable production of the wind.

Whereas this type of drive CCGT depends on the nature of the wind in the area, frequent switching of the CCGT plant and the associated high costs are expected [15]. Therefore, two cases are examined.

In the technical part of this analysis, the goal is to compare the flexibility of CCGT power plants in monitoring the variable of wind in different time resolutions of the optimization process for both cases. It is expected that with the increase in resolution (using a minute resolution instead an hour) the effort for the CCGT power plant, from a technical perspective, becomes increasingly difficult. The corresponding total and specific operating costs CCGT plant are determined.

2.2. Three cases for analysis

In the first case, CCGT and wind offer a fixed amount of the power equivalent to the installed capacity of wind, with variable production balanced by the CCGT. In this case, the expected frequent start up and shut down of the CCGT can occur, as well as significant associated costs since the CCGT has a minimum stable power output (power output does not vary from 0 to P_{max} but from P_{min} to P_{max}).

In the second case, it is assumed that the CCGT and wind offer a fixed amount of power that is greater than the total installed wind power capacity by an amount greater than the minimum stable power output of the CCGT. This avoids frequent start up and shut down, which should reduce specific operating costs of the CCGT power plant.

In the third case analysed, the flexibility and production from the CCGT depend on the number of units of gas and steam turbines.

2.3. Market perspective of the common offering of CCGT and wind power plant

In the second part of the analysis of the current market position of wind, in which the incentive price in the system feed-in guarantees the purchase of the entire produced electricity, is opposed to the full exposure to market conditions — in other words, exposure to the market price of electricity and responsibility for the deviation of the planned and actual production of electricity.

Because there are still insufficiently accurate and reliable methods of forecasting the production of wind [16, 17, 18], wind power plants are forced to find an appropriate way of balancing its production in real time. This paper uses an assumption that the stated balance is achieved by using a CCGT power plant.

The goal is to determine the competitiveness of the CCGT power plant against the electricity market based on a model that takes into account all necessary parameters of wind and CCGT power plant, as is explained in the following section.

Since most of the variable costs of production of CCGT power plant are related to fuel cost, several scenarios with different gas prices are examined in this analysis. Thereby, in this part of the analysis, the temporal resolution of the optimization process will not vary (resolution will constantly be 1 h). More information can be found in the case study section.

3. DESCRIPTION OF THE MODEL

PLEXOS is a software tool for modelling and simulation of relations on the electricity market with a prominent, comprehensive range of features delivered through a simple interface. It is a general simulation tool based on object modelling, which defines a hierarchical set of classes while the user of the simulator creates parts or the entire system by designing instances of objects.

The following characteristics are used for the detailed model of the CCGT power plant according to the given input data:

- Number of units of gas and steam turbines;
- Installed capacity (maximum);
- Minimum stable power;
- Detailed heat rate curves;

— FO&M fee;
— VO&M fee;
— Startup cost for multiple start profiles;
— Startup time for multiple start profiles;
— Lifting speed of power at the start for multiple start profiles;
— Lifting speed of power in operating mode;
— Lowering speed of power in operating mode;
— Motor fuel;
— The fuel used at startup;
— Fuel consumption at the start for multiple start profiles;
— Fuel prices;
— Production emissions;
— Price of emissions;
— Limitation of the production;
— Limitation of the start;
— Auxiliary consumption of the power plant and others.

3.1. Model of the environment of the CCGT power plant in PLEXOS tool

3.1.1. Specificity in the terms of modelling of the renewables.

There is data available for the production of wind power plants in Croatia in hour and minute resolutions. Based on this data, basic statistical parameters are used for modelling the output power of wind in PLEXOS as a stochastic variable with default parameters.

3.1.2. Modelling of the power consumption.

Since only the coordination of a wind and CCGT power plant are analysed, the consumption of a particular region is not being modelled. Consumption is considered as a fixed amount and is equal throughout the entire optimization period.

3.1.3. Modelling of the dummy power plant.

A dummy generator is modelled in the cases where the CCGT power plant cannot cover residual consumption due to technical capabilities. The dummy generator is a super flexible generator for starting and lifting power. Its operating costs are significantly higher than the costs of the CCGT, so the dummy generator is activated only in cases where CCGT power plant achieves technical limits. For the purpose of the analysis, the modelled dummy generator has maximum capacity of 500 MW and VO&M cost of 5000 €/MWh. It should be noted that the value of lost load in the model is fixed on 100 000 €/MWh to ensure activation of the dummy generator only in case of an emergency and the generator activation price is 1 000 000 €.

4. CASE STUDIES 1 & 2

This part of the paper describes the details of the CCGT model in a single-shaft version with different time resolutions (from 1 hour to 1 minute) for input data (wind plant production and CCGT plant characteristics).

4.1. CCGT model

In Table 1 and Table 2 are the basic data of CCGT. Sources for the given data can be found in [19, 20, 21, 22, 23, 24, 25].

TABLE 1 INPUT DATA FOR GAS AND STEAM TURBINE

	MAX. CAP. (MW)	MIN. STABLE LEVEL (MW)	VO&M (€/MWh)	FO&M (€/kW/year)	
GT	307	61.4	3.22	20	
ST	138	27.6	3.22	20	
	AUX (MW)	RAMP RATE (MW/min)	Eff. 100% (%)	Eff. 80% (%)	Eff. 20% (%)
GT	10	15.35	40	38	23
ST	4	6.9	31.17	31.17	31.17

TABLE 2. CCGT START PROFILE DATA

START	IDLE TIME (hrs)	FUEL OFFTAKE (GJ)	START COST (€)	START TIME (min)
Hot	8	89.2	10 235	30
Warm	48	93.9	14 685	90
Cold	96	112.67	20 025	190

4.1.1. Wind model

The data used to model the variability of output power from wind can be found in Table 3. The same data is used independent of the time resolution of the optimization procedure.

TABLE 3. WIND POWER OUTPUT STOCHASTIC PARAMETERS

CASE	MIN VALUE (MW)	MAX. VALUE (MW)	MEAN VALUE (MW)	Std. Dev. (MW)
Case 1	0	400	102	97
Case 2	0	280	71	68

Data in Table 3 are scaled on the basis of the calculated statistical data for the output of wind power in Croatia according to the maximum output power of the wind. It is assumed that the relationship between the expected value, expected error, and maximum amount are fixed compared to the capacity of the wind.

4.1.2. Electricity consumption model

Consumption of electricity is 400 MW in each time period.

4.2. Results and discussion

Because of the complexity of the model and the many technical constraints and in order to keep the same power output profile of the wind (for easier and more reliable comparison of results), for all analysed time resolutions in individual cases the duration of the optimization is set according to a set time resolution of the simulation so that the total number of analysed time intervals is constant (in this case 60) according to the Table 4.

TABLE 4. OPTIMIZATION TIME HORIZON DATA

TIME RESOLUTION (min)	1	5	10	60
TOTAL OPTIMIZATION DURATION (h)	1	5	10	60

4.2.1. Technical limitations of the CCGT power plant

In the section 'description of the problem and methodology' the results are shown in two cases as follows.

Case 1:

The production of wind in intervals in Case 1 (independent of time resolution) is shown in Fig. 5. Given that the results of the optimization analysis which have a different length but the same number of the time interval (60) will be compared, instead of comparing undelivered energy the undelivered power is compared between the analysed cases. In Fig. 5, the wind power plant power output in Case 1 is shown and in Fig. 6 the CCGT unserved power (Case 1) comparison of undelivered power of the CCGT power plant for Case 1 is given in different time resolutions.

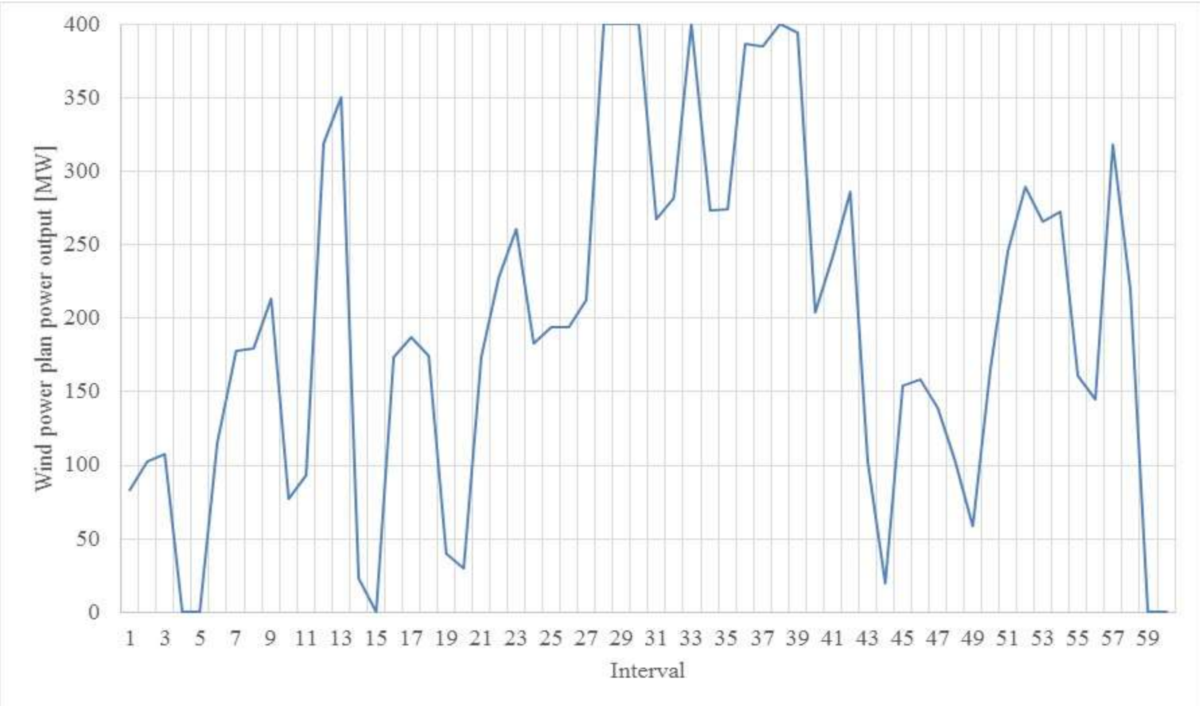


FIG. 5. Wind power plant power output in Case 1.

The average undelivered power per hour is drastically different depending on the time resolution of the optimization. For the time resolution of 1 min average, the undelivered power is 123.8 MW; for the time resolution of 5 min, the undelivered power is 26.6 MW; for 10 min 9.7 MW; for 60 min is only 1.4 MW. The reason for the large differences in undelivered power lies in power change speed limit and limits in starting of the CCGT power plant. Those limits become more frequent when the resolution time of the optimization process is shorter (shorter time interval). When resolution time is 60 min neither of these limits is reached within the time interval (too rough resolution). However, even in the resolution time it can be noticed that there remains a certain level of non-suppled power (purple line). In this case, the limit of the minimum working point of a CCGT plant leads to an unmet need for power. In cases where the difference between total demand (400 MW) and the power output of wind is less than the minimum stable level of the CCGT power plant, the CCGT will not be able to meet the necessary difference. In Case 2, this occurrence is avoided and it is possible to compare purely technical limitations related to the increasing speed power of the CCGT in normal operation.

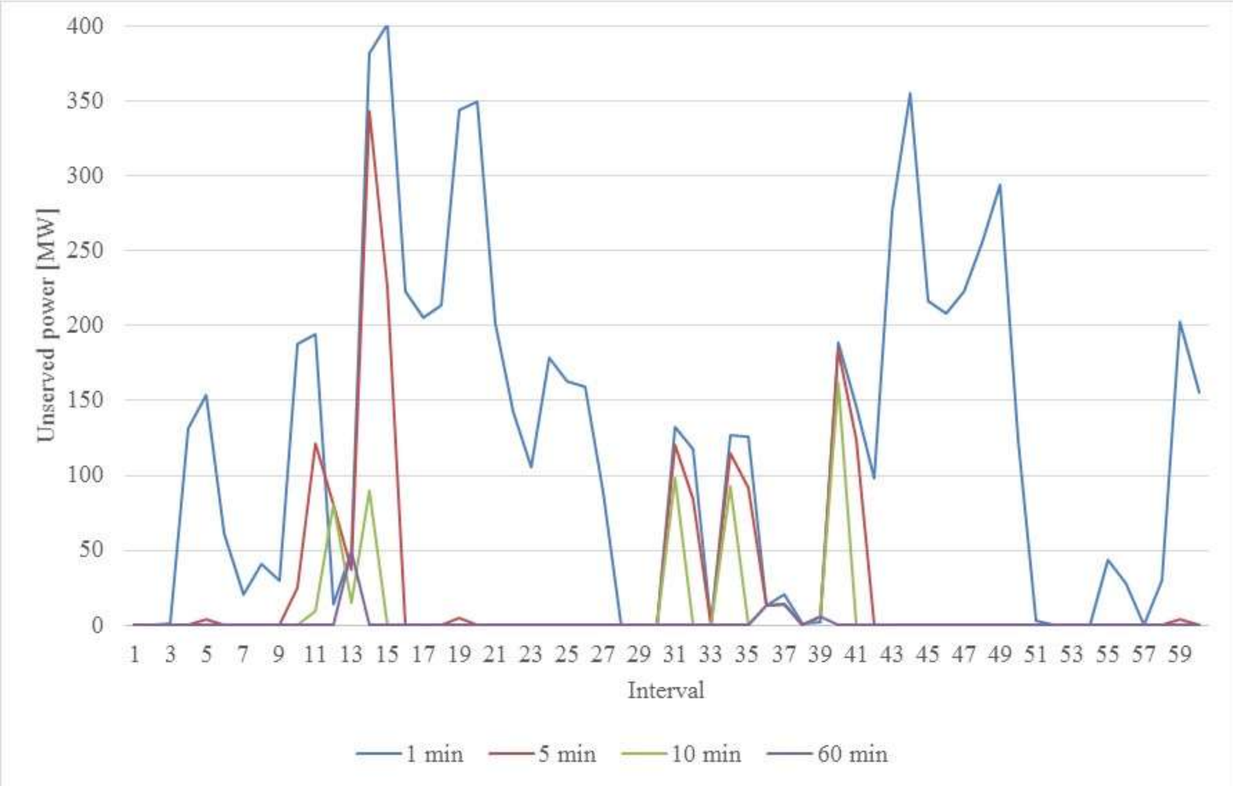


FIG. 6. CCGT unserved power (Case 1).

Case 2:

The production of the wind in intervals in Case 2 (independent of time resolution) is shown in Fig. 7.

As in the Case 1, the undelivered power between the analysed cases are compared. Fig. 8 shows the comparison between undelivered power in different time resolutions for Case 2.

Because of the possibility that the CCGT power plant works continuously (does not have to go through slow starts) and because there is more adequate wind characterization than in Case 1, the undelivered power is significantly lower than in Case 1. The average undelivered power per hour for a time resolution of 1 min is 66.5 MW; for 5 min at 3.1 MW; while for 10 min and 60 min resolution, the undelivered power is not recorded. By comparing Case 1 and Case 2 it is possible to conclude that the CCGT power plant significantly monitors wind power better when it is not forced to perform frequent switching.

4.2.2. Market perspective

The question is: whether, and under what conditions CCGT power plant, as a supplement for the production from the wind, is this coordination more competitive than buying electricity on the electricity market? Since the price of gas is the most influential factor for the production cost of CCGT power plants, the gas prices in this analysis varies between 2 €/GJ and 8 €/GJ by increments of 2 €/GJ for any individual cost. For all costs, an optimization procedure is performed as well as an analysis of the amount of energy produced by the CCGT and amount of energy which was bought in the electricity market. The power consumption is again fixed at 400 MW.

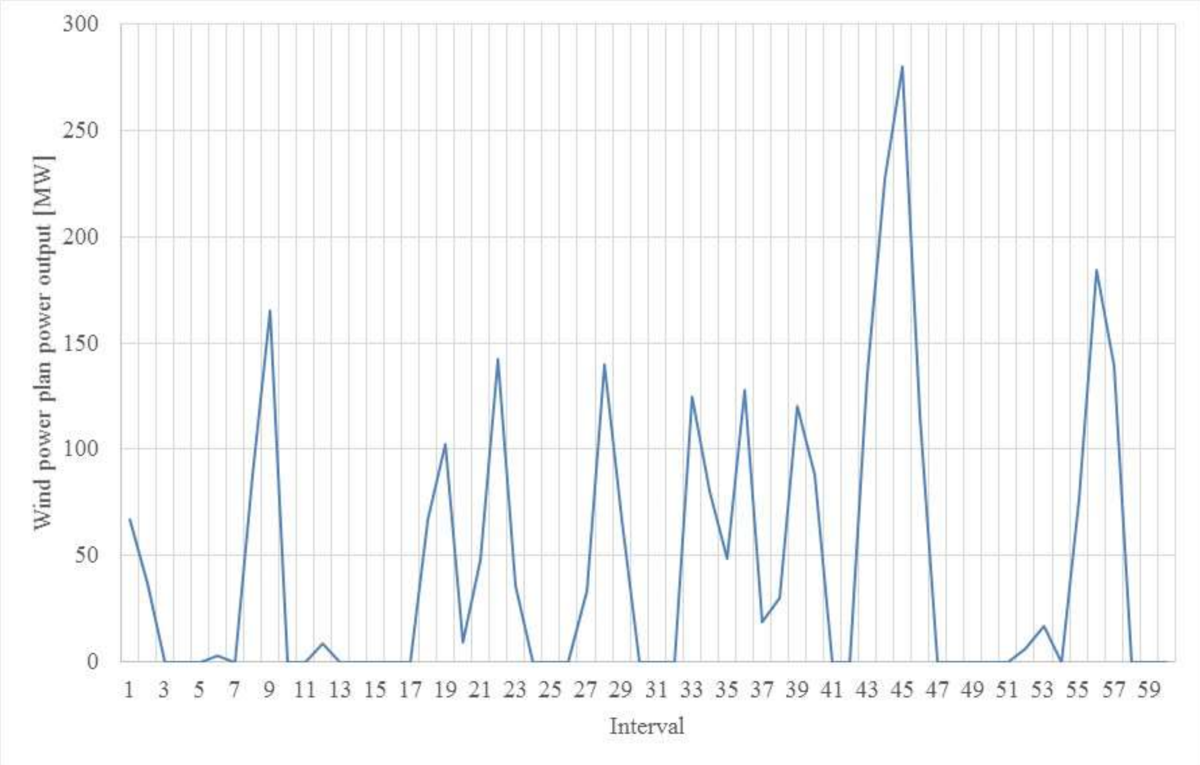


FIG. 7. Wind power plant power output in Case 2.

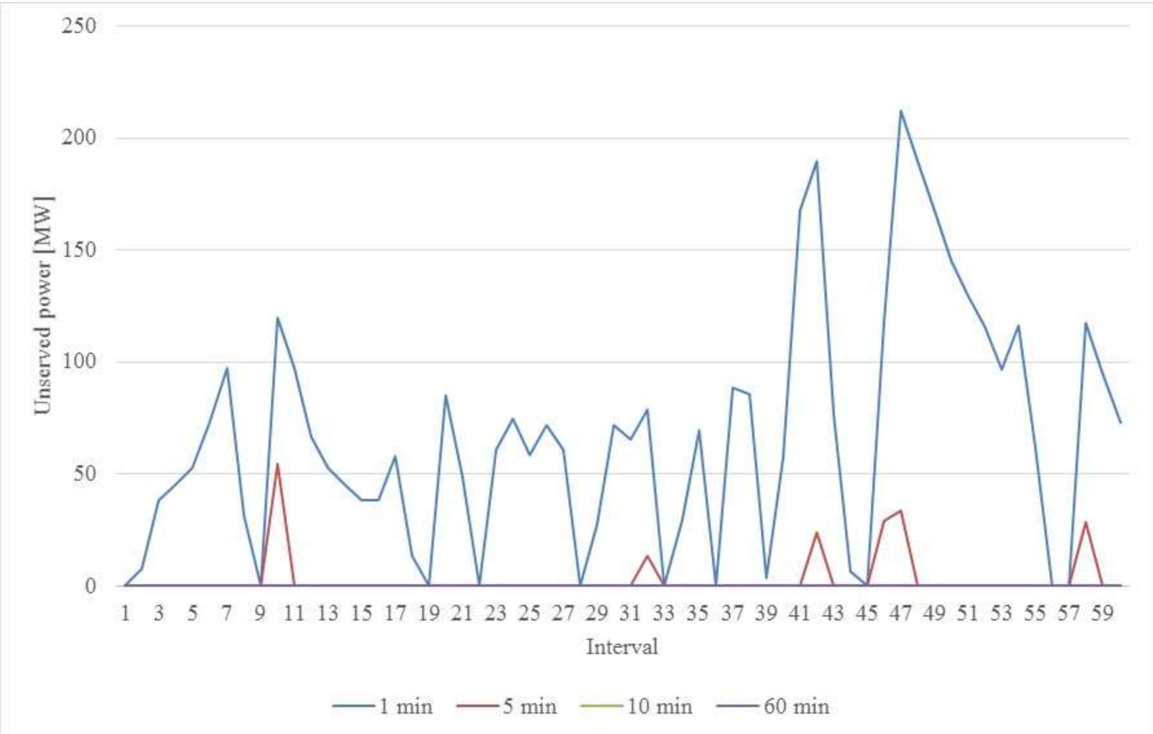


FIG. 8. CCGT unserved power (Case 2).

A period of one month is analysed with stochastic parameters of wind as in Table 3 for Case 2.

The prices of electricity are taken from the stock exchange EPEX for January 2014. From analyses it can be clearly seen that the increase in the gas price has drastic consequences in terms of reducing the production of CCGT power plants. It is clearly evident that the production of the CCGT is highest in periods when the price of electricity is highest. The average price of electricity on the market in the analysed period is 35.8 €/MWh. The total demand for electricity was 297.6 GWh. Wind covered 81.55

GWh, or 27.4%, of demand. The rest of the demand was met by CCGT and the electricity market in different proportions depending on the gas price. Table 5 shows the contribution of each source of electricity depending on the gas price.

TABLE 5. SHARE OF EACH ELECTRICITY SOURCE FOR DIFFERENT GAS PRICES

FUEL PRICE	SHARE OF WIND FARM	SHARE OF CCGT	SHARE OF MARKET
2 €/GJ	27.4%	70.1%	2.5%
4 €/GJ	27.4%	51.3%	21.3%
6 €/GJ	27.4%	20.2%	52.4%
8 €/GJ	27.4%	0%	72.6%

With the very low cost of gas of 2 €/GJ, the modelled CCGT is almost constantly more competitive than the electricity market. With 4 €/GJ (equivalent to the price of gas on the EPEX Stock Exchange on 20/07/2016), the ratio of CCGT production and market purchase is 2.5 in favour of the CCGT. The situation is exactly opposite when the gas price is 6 €/GJ, but for the gas price of 8 €/GJ in the observed period, the CCGT did not run a single hour.

4.3. Results and discussion for Cases 1 and 2

This analysis is focused on the technoeconomic analysis of possibilities of balancing the volatile nature of wind power using CCGT power plants. The technical characteristic of CCGT power plants provide balance for the wind, but also have limitations. A limitation is especially evident in the limited speed of raising power and limited speed of start. In order to avoid restrictions associated with the start of the CCGT power plant it is desirable that the CCGT constantly works at a power above the minimum stable level. Therefore, a fixed amount which is jointly offered by wind and CCGT in an observed period should be equal to, or greater than the sum of the expected maximum power output of the wind and the minimum stable level of the CCGT power plant. The analysis shows how the variability of the wind affects reaching of the technical limitation of CCGT power plants through optimization in different time resolutions. It has been shown that, with the same wind variability, in the optimization with higher time resolution, the main technical limitations of the CCGT power plant are emphasized, especially with regard to the rise and fall speed of the output power. Therefore, with this kind of analysis it is necessary to collect quality data at the best possible resolution and then adequately model wind power plants and adjusts resolution time in the optimization process in order to get meaningful and usable results. The analysis also shows how the use of the statistical data in hour resolution in the optimization process, compared with significantly higher resolution (e.g. 1 min), results in significantly higher demand on the CCGT power plant. This reaffirms the need to coordinate the resolution time of the input data which is based on the stochastic modelling of wind and resolution time (interval) of the optimization as well as similar problems.

In terms of economic feasibility, the balancing of wind power output by CCGT power plants in the optimization model in hour resolution is compared to the competitiveness of the CCGT plant in relation to the electricity market as an alternative to balancing. It is shown that the greatest impact on competitiveness or production costs of the CCGT power plant comes from the price of fuel — gas. It turned out that in the case of gas prices that are half the size of the prices today, CCGT is almost always the cost effective option. On the other hand, if prices are twice the size of today's, the external market completely dominates and the CCGT does not record any production in the considered case. At current gas prices, which are about 4 €/GJ, CCGT is more competitive than the external market. It is necessary to emphasize that the results depend on the electricity prices and the stock market from which the same are taken. Recommendations for further research are to put an emphasis on variability and expected movement trends in electricity prices in the market.

5. CASE 3 (CCGT WITH DIFFERENT NUMBERS OF GT)

5.1. CCGT model

This analysis is related to the technical ability (i.e. flexibility) of CCGT power plants for following variable production of the wind. Whereas the considered type of drive CCGT depends on the nature of wind in the area, frequent switching of the CCGT plant and an associated high cost are expected [15]. Therefore, three different models are analysed: 1+1 model (one steam and one gas turbine), 2+1 model (one steam and two gas turbines) and 3+1 model (one steam and three gas turbines). All three models have the same major characteristics: total installed capacity, as the other related features such as part load efficiency etc. In Table 6, Table 7, Table 8 and Table 9 CCGT data taken from [19, 20, 21, 22, 23, 24, 25] is shown.

TABLE 6. INPUT DATA FOR GAS AND STEAM TURBINE — 1+1 MODEL

1+1 MODEL	MAX. CAP. (MW)	MIN. STABLE LEVEL (MW)	VO&M (€/MWh)		FO&M (€/kW/year)
GT	307	61.4	3.22		20
ST	138	27.6	3.22		20
	AUX (MW)	RAMP RATE (MW/min)	Eff. 100% (%)	Eff. 80% (%)	Eff. 20% (%)
GT	10	15.35	40	38	23
ST	4	6.9	31.17	31.17	31.17

TABLE 7. CCGT START PROFILE DATA — 1+1 MODEL

START	IDLE TIME (hrs)	FUEL OFFTAKE (GJ)	START COST (€)	START TIME (min)
Hot	8	89.2	10235	30
Warm	48	93.9	14685	90
Cold	96	112.67	20025	190

TABLE 8. INPUT DATA FOR GAS AND STEAM TURBINE — 2+1 MODEL

2+1 MODEL	MAX. CAP. (MW)	MIN. STABLE LEVEL (MW)	VO&M (€/MWh)		FO&M (€/kW/year)
GT1=GT2	153.5	30.7	3.22		20
ST	138	27.6	3.22		20
	AUX (MW)	RAMP RATE (MW/min)	Eff. 100% (%)	Eff. 80% (%)	Eff. 20% (%)
GT1=GT2	5	7.7	40	38	23
ST	4	6.9	31.17	31.17	31.17

TABLE 9. INPUT DATA FOR GAS AND STEAM TURBINE — 3+1 MODEL

3+1 MODEL	MAX. CAP. (MW)	MIN. STABLE LEVEL (MW)	VO&M (€/MWh)	FO&M (€/kW/year)	
GT1=GT2=GT3	102.33	20.47	3.22	20	
ST	138	27.6	3.22	20	
	AUX (MW)	RAMP RATE (MW/min)	Eff. 100% (%)	Eff. 80% (%)	Eff. 20% (%)
GT1=GT2=GT3	3.33	5.117	40	38	23
ST	4	6.9	31.17	31.17	31.17

The following characteristics are used for the purpose of creating a detailed model of the CCGT power plant according to the given input data:

- Number of the units of the gas and steam turbines;
- Installed capacity (maximum);
- Minimum stable power;
- Detailed heat rate curves;
- FO&M fee;
- VO&M fee;
- Startup costs for multiple start profiles;
- Startup time for multiple start profiles;
- Lifting speed of power at the start for multiple start profiles;
- Lifting speed of power in operating mode;
- Lowering speed of power in operating mode;
- Motor fuel;
- Fuel consumption at the start for multiple start profiles;
- Fuel prices;
- Limitation of the production;
- Limitation of the start;
- Auxiliary consumption of the power plant and others.

Each scenario has five cases with different maximum values, mean values and deviations. Case one is wind with the highest maximum value (400 MW) and Case 5 has the lowest maximum value (100 MW). The data used for wind modelling can be found in Table 10 and Table 11.

TABLE 10. WIND POWER OUTPUT STOCHASTIC PARAMETERS FOR WIND CAPACITY FACTOR 33% AND 24%

	MIN. VALUE (MW)	MAX. VALUE (MW)	MEAN VALUE (MW)
Case 1	0	400	104
Case 2	0	300	78
Case 3	0	200	52
Case 4	0	150	39
Case 5	0	100	26

TABLE 11. WIND POWER OUTPUT STOCHASTIC PARAMETERS FOR WIND CAPACITY FACTOR 61%

	MIN. VALUE (MW)	MAX. VALUE (MW)	MEAN VALUE (MW)
Case 1	0	400	200
Case 2	0	300	150
Case 3	0	200	100
Case 4	0	150	75
Case 5	0	100	50

5.2. Electricity consumption model

Consumption is a fixed amount throughout the entire optimization period, but different in each scenario. Consumption changes depending on the modelled wind power level.

5.3. Results and discussion for Case 3

Fig. 9 represents wind with a capacity factor 33% and maximum power output of 100 MW. Fig. 10 is wind with a capacity factor 24% and maximum power output of 100 MW. Wind with a capacity factor of 33% and wind with capacity factor of 24% have the same average power and standard deviation. Fig. 11 is wind with a capacity factor 61%. The profile and deviation of wind on Fig. 11 is higher can be characterized as a strong wind. Each figure represents the data for one week with hourly resolution.

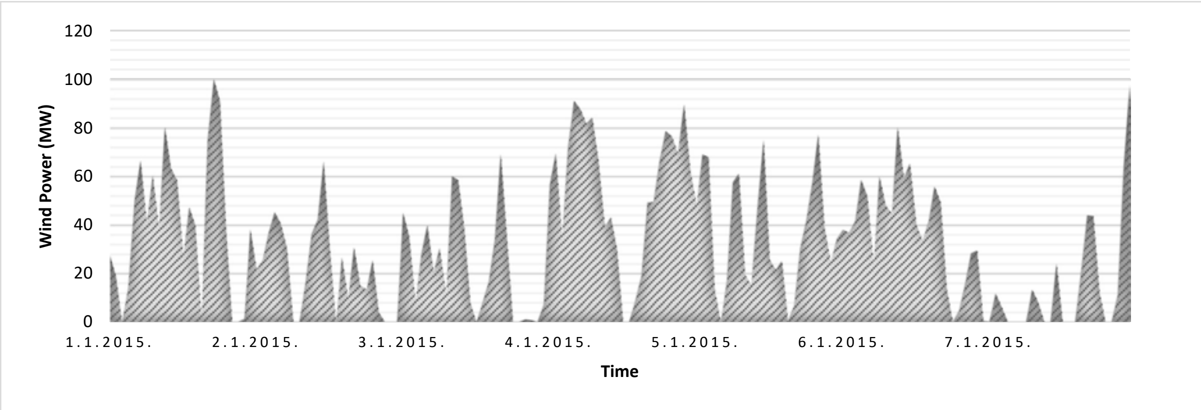


FIG. 9. Profile of wind, capacity factor = 33%, case 5 (max wind power 100 MW).

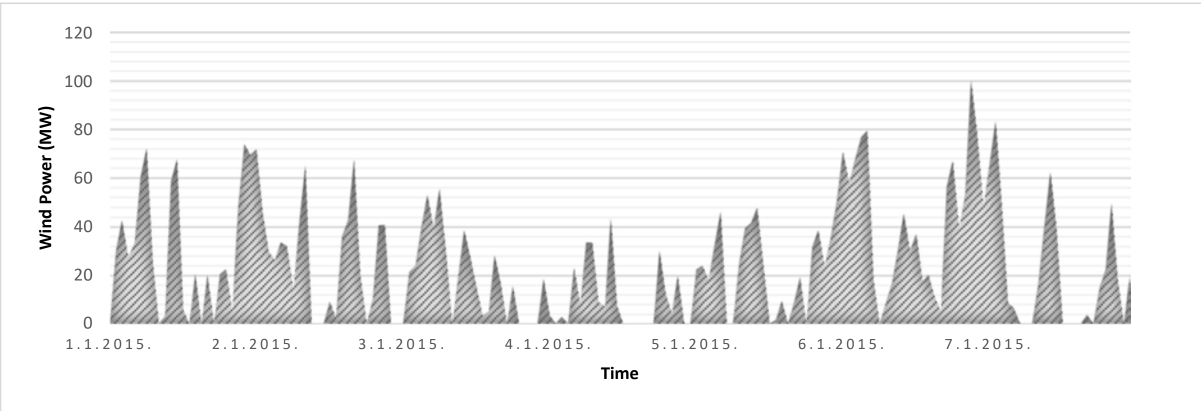


FIG. 10. Profile of wind, capacity factor = 24%, case 5 (max wind power 100 MW).

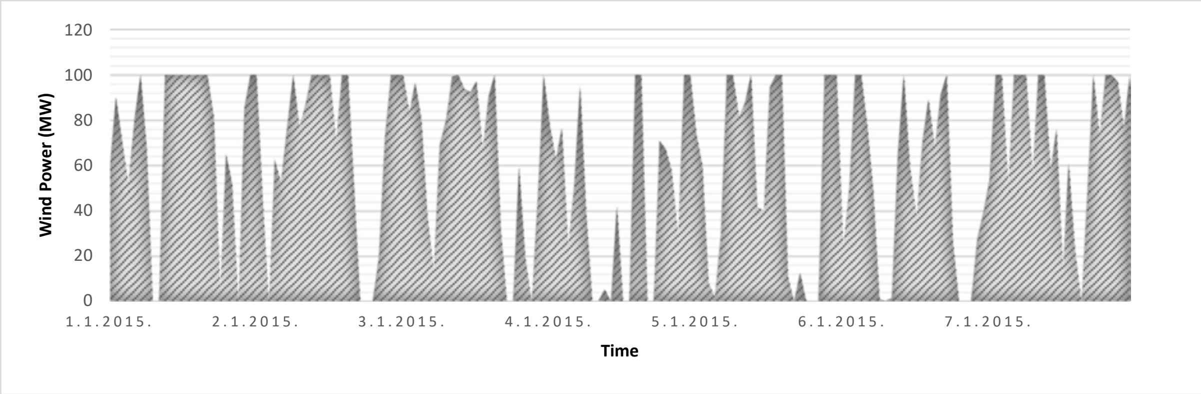
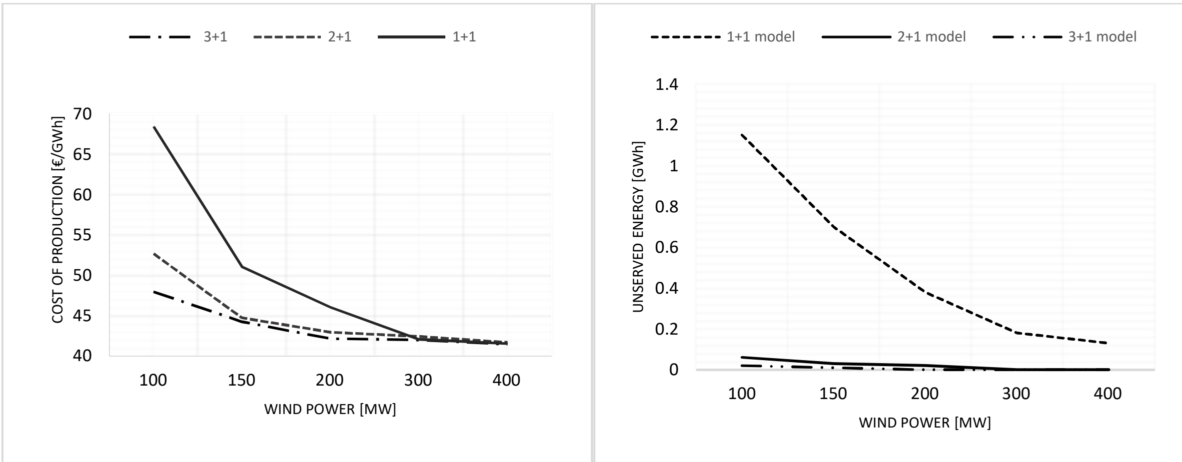


FIG. 11. Profile of wind, capacity factor = 61%, case 5 (max wind power 100 MW).

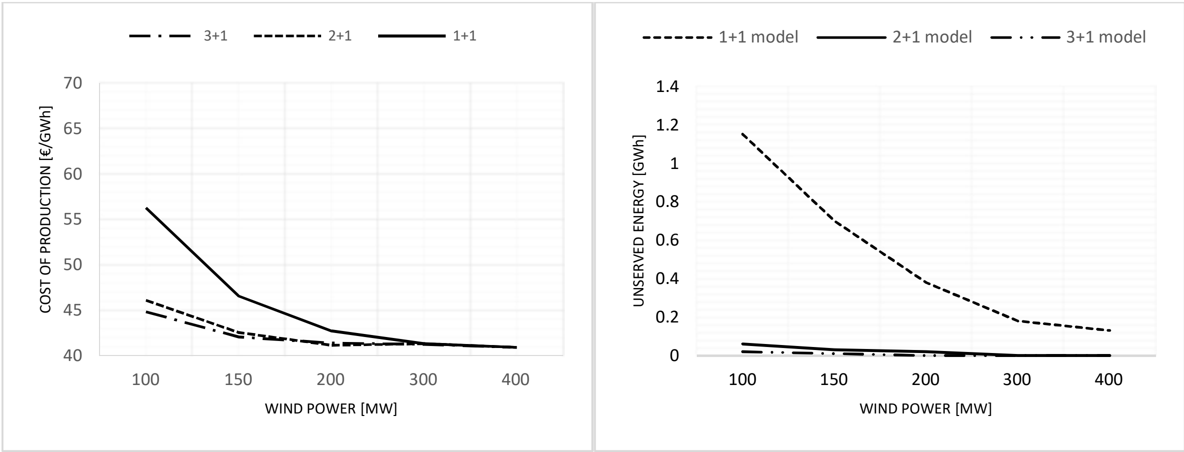
In this analysis, the cost of production and unserved energy are analysed for three models of CCGT power plant: 1+1 model (CCGT with one gas turbine and one steam turbine), 2+1 model (CCGT with two gas turbines and one steam turbine) and 3+1 model (CCGT with three gas turbines and one steam turbine). Results from the optimization can be found in the following figures. In the left column are the cost of production and in the right column is unserved energy for the Case 5 (maximum wind power of 100 MW) in three different scenarios (wind capacity factor 33%, 24% and 61%).



(a) *(b)*

FIG. 12. (a) Cost of production and (b) unserved energy for 1+1, 2+1 and 3+1 model for scenario 1 (wind capacity factor = 33%) and Case 5 (wind production 5.54 GWh).

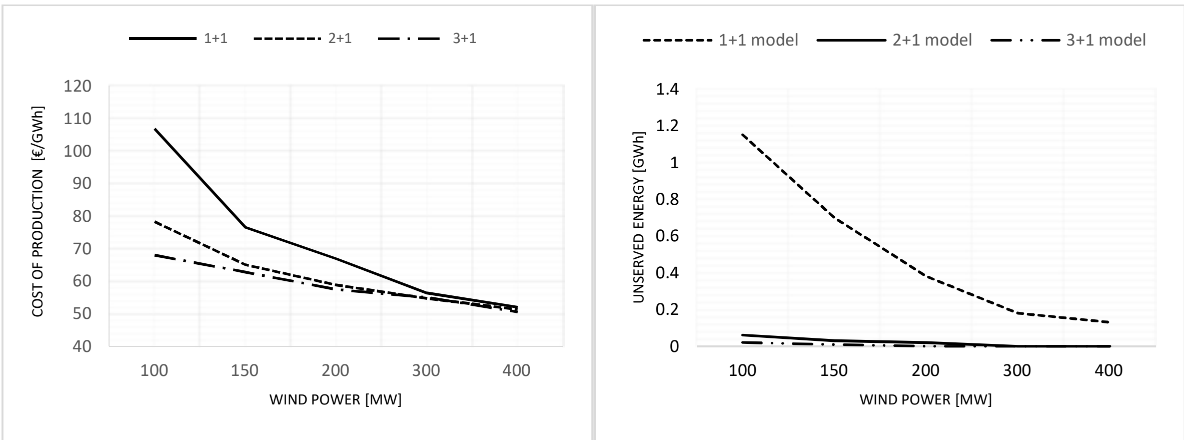
Each figure (FIG. 12a, FIG. 13a and FIG. 14a) shows that wind nature, which CCGT is balancing, has a significant impact on the decided number of gas turbines. On the lower wind power levels, it is very important whether the CCGT has one, two or three gas turbines. The CCGT with one gas turbine has a lower efficiency at low power outputs (100–200 MW) than the CCGT with two or three gas turbines. Due to the lower flexibility, the CCGT with one gas turbine has to shut down and start up more often, resulting in increased costs (startup cost, consumption of fuel). That difference is significant: in the scenario with a wind capacity factor of 61%, the difference in cost of production between the CCGT model with one and three gas turbines is slightly less than 40 €/GWh. If the wind power level in the system is higher (300–400 MW), the differences in these costs becomes smaller, especially the difference between CCGT models with two and three gas turbines. If the wind power is higher than 150 MW, then both the two turbines and three turbines models have very high efficiency and flexibility regarding balancing of the wind production. For the power levels higher than 300 MW, the number of gas turbines is no longer important because the costs of production are almost the same — all three models have high efficiency at these power levels.



(a) *(b)*

FIG. 13. (a) Cost of production and (b) unserved energy for 1+1, 2+1 and 3+1 model scenario 2 (wind capacity factor = 24%) and Case 5 (wind production 5.54 GWh).

It is also very important to notice the influence of the wind capacity factor on CCGT production costs. In the scenario with the largest wind capacity factor (capacity factor 61%), the CCGT cost of production is significantly larger in comparison to scenarios with lower wind capacity factors (capacity factors 33% and 24%), regardless of the wind power level and the CCGT model. As can be seen from FIG. 12b; FIG. 13b and FIG. 14b, unserved energy in each scenario depends on the number of gas turbines. For the CCGT power plant with one gas turbine, the unserved energy is significantly higher than the unserved energy for the CCGT plant with two or three turbines due to the higher minimum stable level value.



(a) *(b)*

FIG. 14. (a) Cost of production and (b) unserved energy for 1+1, 2+1 and 3+1 model for scenario 3 (wind capacity factor = 61%) case 5 (wind production 5.54 GWh).

Detailed data regarding the production of each power plant in the modelled system for each scenario and case can be found in Table 12; Table 13 and Table 14.

TABLE 12. PRODUCTION OF CCGT, DUMMY AND WIND POWER PLANT FOR SCENARIO 1

MODEL	LOAD [MW]		100	150	200	300	400
1+1	PRODUCTION [GWh]	CCGT	10.11	16.2	22.15	33.61	44.93
		Dummy	1.15	0.7	0.38	0.18	0.13
		Wind	5.54	8.3	11.07	16.61	22.14
2+1		CCGT	11.2	16.87	22.51	33.79	45.06
		Dummy	0.06	0.03	0.02	0	0
		Wind	5.54	8.3	11.07	16.61	22.14
3+1		CCGT	11.24	16.89	22.53	33.79	45.06
		Dummy	0.02	0.01	0	0	0
		Wind	5.54	8.3	11.07	16.61	22.14

TABLE 13. PRODUCTION OF CCGT, DUMMY AND WIND POWER PLANT FOR SCENARIO 2

MODEL	LOAD [MW]		100	150	200	300	400
1+1	PRODUCTION [GWh]	CCGT	11.88	18.57	25.32	38.07	50.83
		Dummy	0.83	0.49	0.09	0.05	0
		Wind	4.09	6.14	8.19	12.28	16.37
2+1		CCGT	12.7	19.05	25.41	38.12	50.83
		Dummy	0.01	0.01	0	0	0
		Wind	4.09	6.14	8.19	12.28	16.37
3+1		CCGT	12.71	19.06	25.41	38.12	50.83
		Dummy	0	0	0	0	0
		Wind	4.09	6.14	8.19	12.28	16.37

TABLE 14. PRODUCTION OF CCGT, DUMMY AND WIND POWER PLANT FOR SCENARIO 3

MODEL	LOAD [MW]		100	150	200	300	400
1+1	PRODUCTION [GWh]	CCGT	5.28	3.85	17.59	19.17	25.68
		Dummy	1.23	0.76	0.57	0.35	0.34
		Wind	10.29	20.59	15.44	30.88	41.18
2+1		CCGT	6.29	4.45	18.05	19.46	25.96
		Dummy	0.22	0.16	0.11	0.06	0.06
		Wind	10.29	20.59	15.44	30.88	41.18
3+1		CCGT	6.44	4.58	18.14	19.51	26.01
		Dummy	0.07	0.03	0.02	0.01	0.01
		Wind	10.29	20.59	15.44	30.88	41.18

6. CONCLUSION

This analysis presents a technoeconomic analysis for the balancing of the volatile nature of renewables in this case wind farms (hybrid CCGT–wind power plant system). The analysis of two cases shows how the variability of wind affects reaching of the technical limitation of a CCGT power plant through optimization in different time resolutions. It is shown that, with the same variability of wind in the optimization, with higher time resolution real technical limitations of CCGT power plants come better to the fore, especially in term of the speed of raising and lowering output power. Therefore, with this kind of analysis, it is necessary to collect quality data at the best possible resolution and then adequately model wind power plants and adjust resolution time in the optimization process in order to get the meaningful and usable results. The analysis also shows how the use of statistical data in hour resolution in the optimization process with significantly higher resolution (e.g. 1 min) results in significantly higher demands on the CCGT power plant, which reaffirms the need to coordinate the resolution time of the input data on which the stochastic modelling of wind and resolution time (interval) of the optimization as well as similar problems are based.

In the third case analysis, different CCGT power plant models with a different number of gas turbines were used as a basis for results comparison. Investments in the CCGT power plant with one gas turbine is lower than the investment in CCGT with two or three gas turbines. However, the CCGT with one gas turbine has low efficiency and flexibility at lower loads and consequently higher costs because of limitations as the speed of raising power and speed of the start are limited. Those limitations have a huge impact on the production costs. In order to avoid restrictions associated with the start of the CCGT power plant, it is desirable that the CCGT constantly has a load higher than the minimum stable level — but in the system with a huge share of renewables it is not often possible. If CCGT often works at lower capacity, it is better to have more gas turbines which will results in a decrease of production cost. However, if the load is higher, all three CCGT models will come into the area with good efficiency and all three CCGT models will have almost the same production cost. Keeping in mind the previously statement, it is wise to analyse and predict the most frequent load patterns and roles of the CCGT, especially if the CCGT is supposed to balance wind power output, prior to making important investment decisions such as the number of gas turbines.

From the results of the analysis, it is possible to see which characteristics of flexibility NPPs should have for required production in conjunction with real wind power plants.

Results show that power plants with more generating units (like some SMRs) can provide more flexibility and produce more electricity to the market, making NPPs more feasible.

If the same necessary data regarding NPP characteristics were available, it would be interesting to do the same modelling and analyses as the one that is presented for a hybrid wind–CCGT plant system.

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NUCLEAR POWER PLANT AS "THERMAL HUB" WITH RENEWABLE ENERGY

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Abstract

In order to increase Renewable Energy (RE) in the power generation, the present technology of Nuclear Power Plants (NPPs) should be utilized. This paper introduces a 'Thermal Hub' concept which consists of the two hybrid systems with Concentrated Solar Power (CSP) for the heating steam in the reheater and Ocean Thermal Energy Conversion (OTEC) for waste heat recovery of discharged water from the NPP. These renewables were chosen based on the NPP's thermodynamic characteristics. Both thermal hybrid systems will contribute to reduce the cost for the electricity of renewables. A useful chart is introduced for visualization of the relationship between nuclear and renewable energies in the various hybrid systems.

1. INTRODUCTION

In order to realize nuclear energy and renewable hybrid energy systems [1], many ideas are being developed. However, more work is needed in order to apply these ideas into actual power plant design. In order to increase the capacity of Renewable Energy (RE), by hybridization with Nuclear Power Plant (NPP), this paper introduces a 'Thermal Hub' concept of hybridizing with Concentrated Solar Power (CSP) for heating steam and Ocean Thermal Energy Conversion (OTEC) for waste heat recovery from the point of view of the thermodynamic characteristics of the presented NPP. A conceptual image of this concept is shown in Fig. 1.

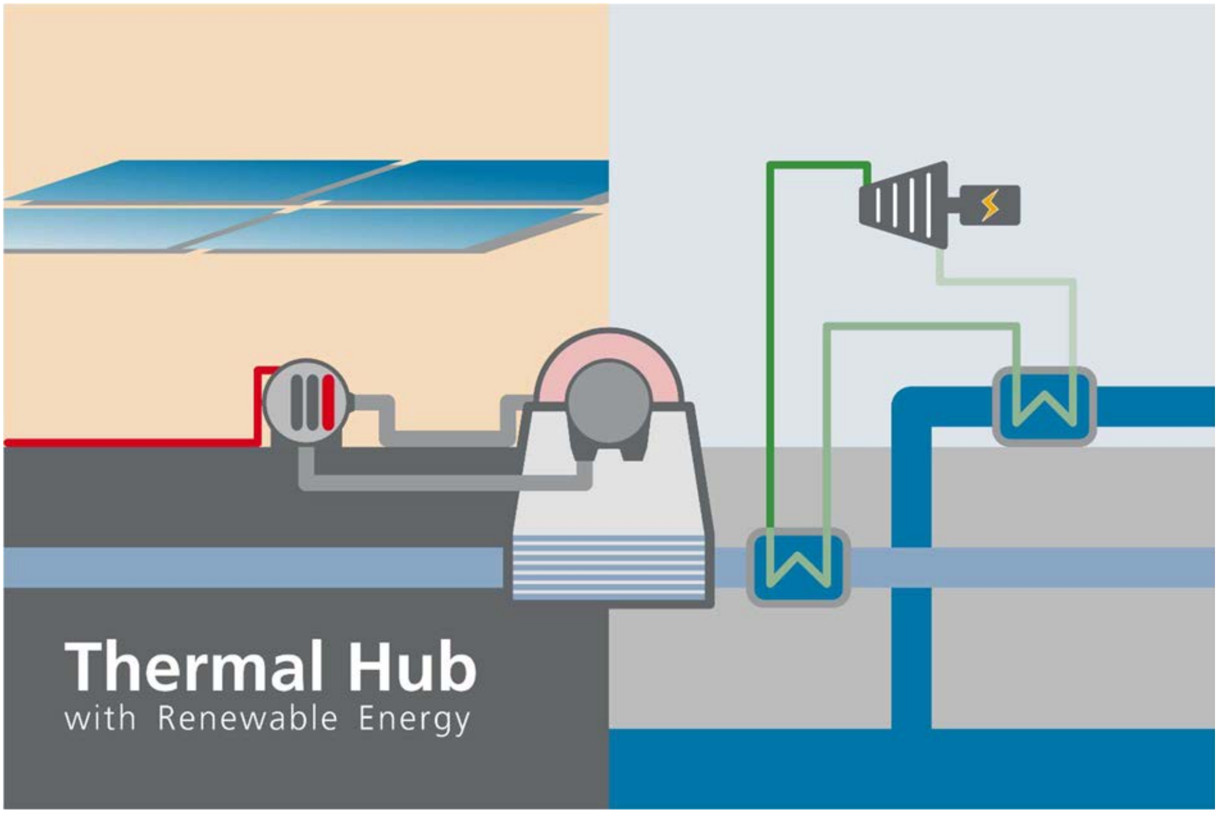

FIG. 1. Conceptual image of 'Thermal Hub'.

2. CHARACTERISTICS OF STEAM TURBINE PLANT FOR NPP

In order to implement appropriate hybridization, better understanding of the characteristics of the Steam Turbine Plant (STP) in the NPP is necessary. In Fig. 2, a schematic diagram of a typical STP is described. In this paper, the reactor is assumed to be a Pressurized Water Reactor (PWR).

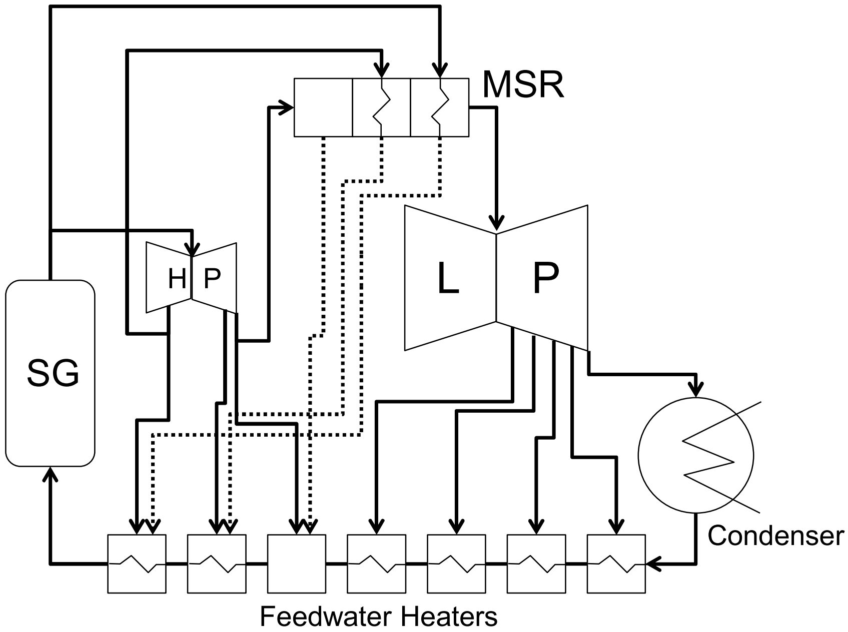

FIG. 2. Schematic diagram of typical STP for NPP (SG: Steam Generator, HP: High Pressure Turbine, LP: Low Pressure Turbine).

The main steam from the Steam Generator (SG) is expanded through the high pressure turbine and will flow into Moisture Separator Reheater (MSR). In the MSR, moisture of exhaust steam is separated, then saturated steam is heated by a two stage reheater before flowing into the low pressure turbine. Exhaust steam from the low pressure turbine returns into water at the condenser. The heat of the exhaust steam cannot be converted to shaft work; therefore, this thermal energy is discharged at condenser. The condensate water will return to the SG with preheating by feedwater heaters which use steam extracted from the steam turbines. There are three important characteristics of STP for NPPs, described as following section.

2.1. Low thermal efficiency

The steam from the SG has a lower enthalpy than that from a fossil boiler. This prevents NPPs from increasing the thermal efficiency, which is typically around 35%. Although higher inlet steam temperature contributes to the better thermal efficiency, the main steam temperature of NPPs is around 270°C. This value is determined by the primary cooling system and is lower than that of fossil power plants, e.g., 600°C in an ultra supercritical coal power plant.

2.2. Large thermal discharge

There is a lot of thermal discharge due to the low thermal efficiency and large thermal input from the nuclear steam supply system. Typical mid class NPPs have 3000 MW thermal input and a thermal efficiency around 35%. Therefore, thermal discharge will be around 2000 MW. Although it may depend on the intake and discharge conditions, the amount of discharged circulating water flow from single NPP will be approximately 200 000 m^3/hr.

2.3. Reheat with moisture separator reheater

The steam turbine is mostly operated in a wet region because the steam quality from the SG is saturated. Therefore, in order to avoid erosion and improve the efficiency of the steam turbine blade, NPPs are equipped with MSR, as mentioned above, since steam cannot be reheated in the SG. A typical MSR is shown in Fig. 3.

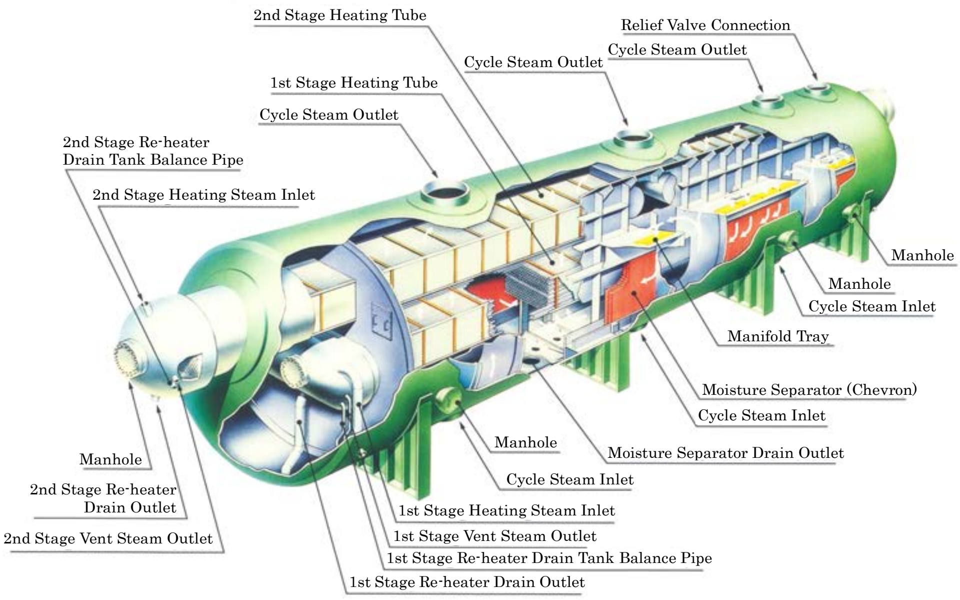

FIG. 3. MSR overview [2].

3. HYBRID SYSTEM WITH RENEWABLE ENERGIES

It is important to use the present NPP technologies which have experience in the world for hybrid systems with RE until the commercial operation of Generation IV NPPs in terms of the accumulation of 'hybrid' operation experience. Therefore, the appropriate RE should be chosen which can take advantage of the characteristics of an NPP as mentioned before. Several REs were investigated in order to choose suitable RE for NPPs, where a typical mid size NPP (~1000 MW_e–1200 MW_e class) is assumed for this study.

3.1. Renewable energies overview

The share of electricity generation by energies is described in Fig. 4. The vertical axis is a logarithmic scale for the better understanding of the growth of RE.

The figure indicates the electricity generated by wind and Photovoltaic (PV) has rapidly increased, but they are not the main source of the electricity in the world yet.

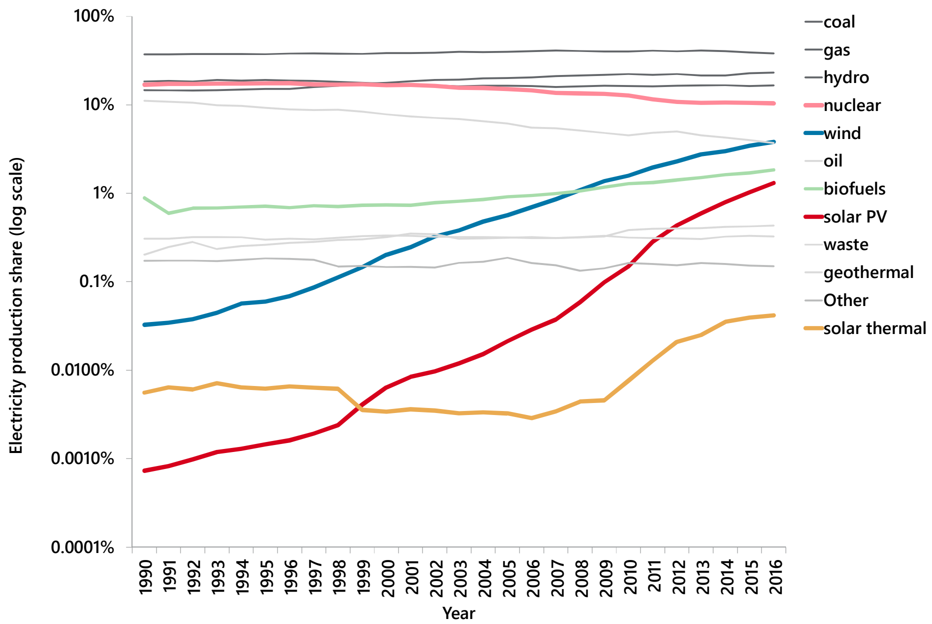

FIG. 4. Electricity production share growth by technology, data retrieved from IEA [3].

3.2. Suitable renewable energies for thermal hybrid

Typical REs are shown in Table 1. REs are generally divided into thermal RE or non-thermal RE. Though the capacity of thermal REs is smaller than that of non-thermal REs (e.g., PV and wind), hybrid systems with these REs will be able to adjust electricity with industrial use (e.g., hydrogen production) or battery storage, etc., and this system can be applied not only NPPs but also to fossil power plants. This kind of hybrid system, however, has no relation with the type of RE or the thermodynamic characteristics of the present NPP.

TABLE 1. TYPE OF REs

THERMAL REs	NON-THERMAL REs
Biomass	PV
Geothermal	Wind
CSP	Hydro
OTEC	Tidal/Wave

In terms of taking advantage of the characteristics of STP in NPP, thermal REs are suitable for coupling with the NPP. The first point to be discussed is which RE is to be coupled with NPP. At first, the biomass boiler may be thermally coupled with NPP. However, the life cycle greenhouse gas emission of biomass may be larger than other REs [4]; thus, for the sake of decarbonization, biomass can be excluded from the list of candidates for thermal hybridization with the NPP. Second, the hybrid system with geothermal may not be appropriate either since it is difficult to build NPPs near geothermal plants. However, advanced reactor designs in the future may pave the way for a geothermal hybrid. Another emerging thermal RE is CSP. CSP has been compared to PV since the source of both is the Sun. The electricity generation cost of CSP, however, is higher than that of PV and the technology improvement and cost reduction are expected for CSP [5]. The share of electricity generation of CSP seems to have reached a plateau after the short period of increase from 2009–2014 as indicated in Fig. 4. As for the rest of thermal RE, OTEC uses the thermal energy of the ocean. It may be thought that OTEC also uses solar energy through sea water. The last two mentioned REs (CSP and OTEC) will be suitable REs for the hybrid with the NPP since they are thermal REs and their locations can be close enough to the NPP for a hybrid system.

3.2.1. Chart for the hybrid system

There will be a lot of possible combinations of hybrid systems to be used for various purposes. In order to clarify the differences in the combinations of energies, a nine region chart is introduced in Fig. 5 and this chart can be called ‘Ennea-gy chart’. The arrow bar indicates the flow or the direction of energy. The red region represents the conventional energy transfer of NPP. The thermal energy from the reactor will change to rotational energy in the steam turbine before generating electricity at the generator. The blue represents the conventional power station of RE. The industrial use or storage of energy are indicated as the grey area between the red and blue area since the industrial or storage equipment will receive the energy from the both power systems. For example, the case of a thermal hybrid system is shown in Fig. 6. The NPP will receive the thermal energy from the RE and will generate more electricity than a sole NPP. This kind of system can be coupled with other equipment which needs the thermal energy for the industrial products, such as the desalination plant for water.

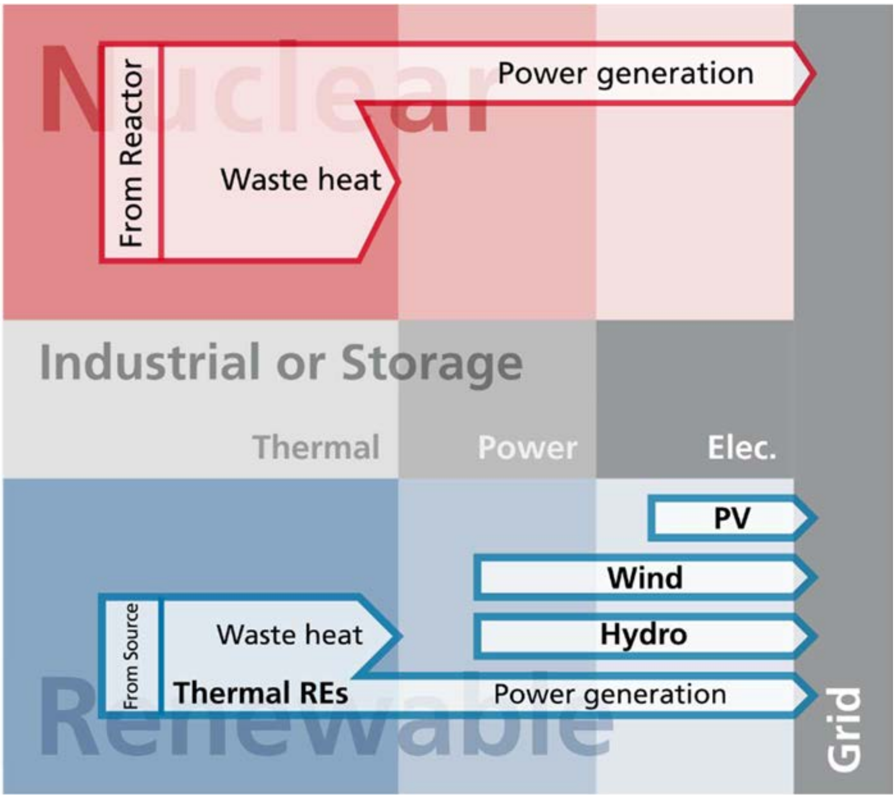

FIG. 5. Energy chart.

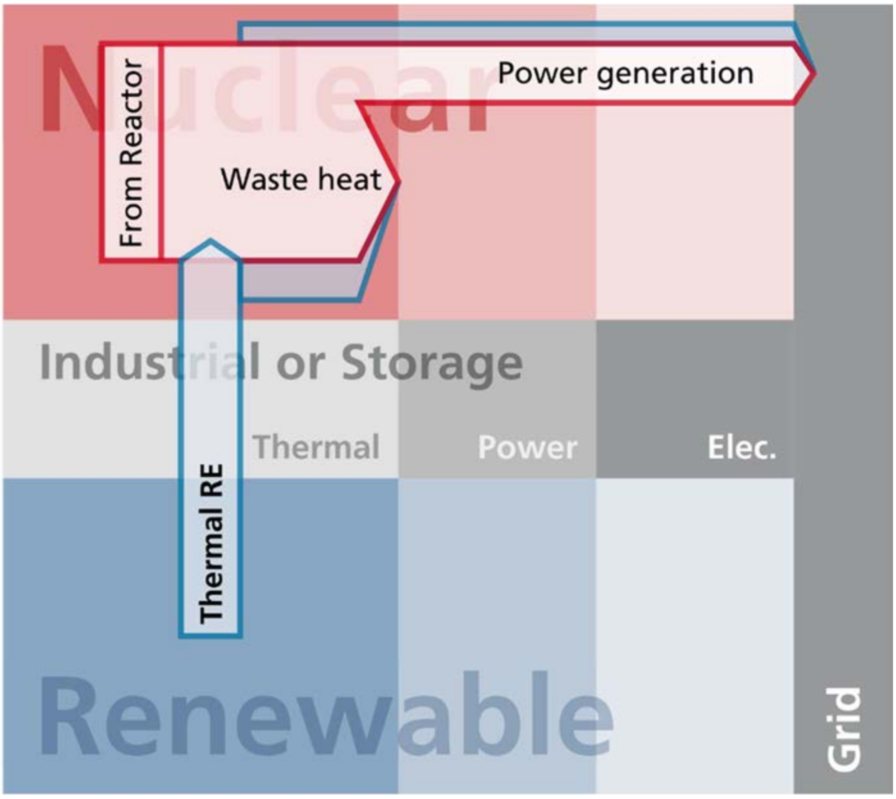

FIG. 6. An example of a thermal hybrid system; the proportion of thermal RE is exaggerated.

3.3. Hybrid system with CSP

From the turbine plant designer's view, CSP seems to be an appropriate thermal source for NPPs because CSP generates higher temperature steam than an NPP. Some fossil power plants are coupled with CSP and this is called as Integrated Solar Combined Cycle (ISCC) [6] and in this cycle CSP will assist the boiler for fuel saving or increasing output during the daytime [7]. In order to merge CSP into an NPP in a better way, the hybrid system should conform to the characteristics of the NPP.

3.3.1. System overview

There are many possible ways to use the steam from CSP with an NPP; for example, a CSP hybrid system that the heat transfer fluid will heat steam before the HP turbine and LP turbine is proposed [8]. However, this paper proposes the Solar Thermal Reheater (STR), with an additional heat exchanger using the steam produced by CSP, as a better way for the following reason:

- The highest temperature in the steam cycle can be achieved with STR.
- To avoiding the contamination, direct injection of steam from CSP is not recommended.
- The piping arrangement can be simplified.

A schematic diagram of an NPP hybrid system with CSP is shown in Fig. 7. The STR is located between the MSR and LP turbine.

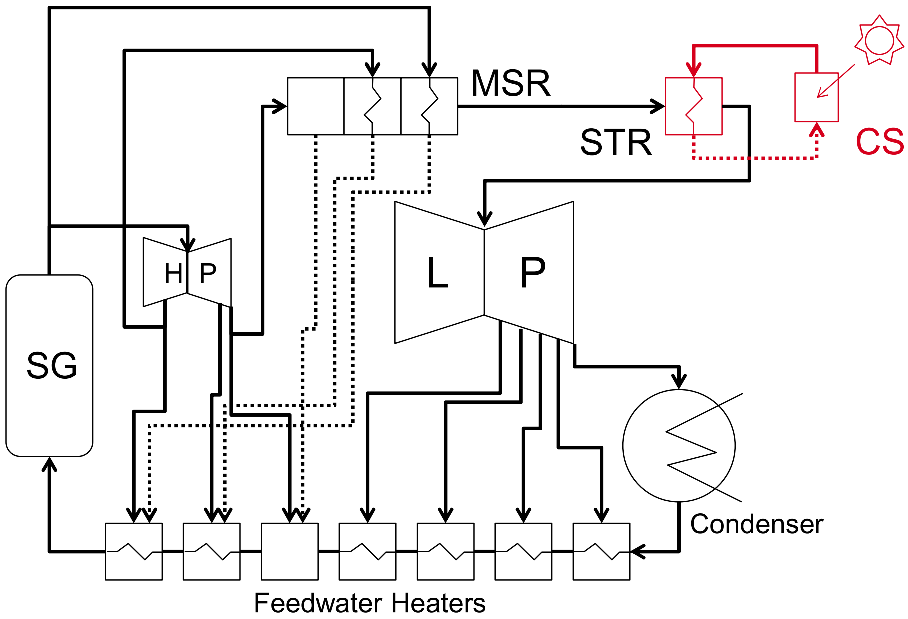

FIG. 7. Hybrid system with CSP.

STR can be installed not only for new projects, but also for the existing NPP. This may contribute to increasing the capacity of CSP and its cost reduction. Thermal storage may also be applicable. The pressure of steam generated by CSP should be more than that of the SG of the NPP for a performance improvement, mentioned later. Approximately 100 MW thermal input from a CSP would be required for increasing steam temperature at the LP turbine inlet from 270°C to 300°C.

3.3.2. Advantages

The proposed hybrid system has some advantages. The advantages will not only be the cost reduction, but also the improvement of thermal performance of the NPP.

3.3.2.1. Cost reduction for CSP

When hybridized with a NPP, the dedicated power block and associated Balance of Plant (BOP) for CSP are not required and these kinds of equipment can be shared with the NPP. This contributes to reduce the cost of electricity originating in the CSP. It is said that the cost of these kinds of equipment will occupy ~10%–20% of the entire cost [9]. Not only superheated, but saturated steam can be applied for STR since latent heat has a better heat transfer than that of superheated. Direct steam generation by parabolic trough or linear Fresnel collectors for the saturated steam generation will reduce the cost of the CSP system.

3.3.2.2. Performance improvement for NPP

The thermal performance of an NPP will be improved with STR since the increased temperature of LP turbine inlet contributes to reducing the wetness of the operating steam in the LP turbine and this means reducing the wet loss of the turbine as shown in Fig. 8. The degree of improvement depends on the thermal input and steam temperature from CSP. This is an important characteristic of the proposed system.

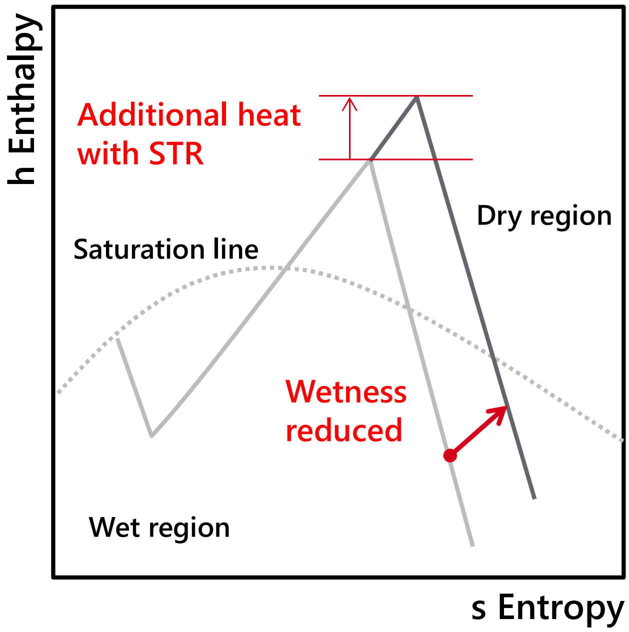

FIG. 8. Schematic expansion diagram of NPP.

3.3.3. Challenges

There are some challenges for this hybrid system. The representative challenges are discussed in this paper.

3.3.3.1. When CSP is out of service

When CSP operates insufficiently, the pressure loss of STR may decrease the plant performance compared with a sole NPP. Bypass piping around the STR can be one of the solutions; however, the necessary equipment for STR bypass, e.g., the extra piping and valves, has extra pressure drops. Another solution is thermal storage. Some CSP plants with thermal storage are commercially operated [10].

3.3.3.2. Plume from cooling tower of NPP

The shade of plume from the Cooling Tower (CT) may have a negative effect on a CSP system if the NPP adopts CT since the size of the CT will be larger by many times than that of CSP power plant. Inland NPPs may be suitable for the CSP hybrid system from the point of view of CSP location. The positional relation between the CT and CSP system should be well investigated during the feasibility study or equivalent phase of design.

3.3.3.3. Economic incentive for RE

If economic incentive for CSP is applicable, the electricity originating from CSP and the performance improvement should be treated as from RE, not from NPP. In this proposed system, although the turbine–generator of the NPP only generates the electricity, the electricity generated may be classified by three internal sources:

- Original NPP;
- CSP;
- NPP performance improvement by CSP, as synthesis of 1 and 2.

3.3.4. Applicable region

In Fig. 9, The locations of NPP [11] and CSP with operational status are registered in a database [12] and are described with daily average Direct Normal Irradiance (DNI) [13]. It is said that the region where the daily average DNI is 5 kWh/m^2 or more is recommended for a CSP plant. These regions such as southern US, Spain, Middle East or inland of China may be suitable for hybrid systems with the present NPP technology.

3.3.5. Hybrid system with small module reactor

A Small Module Reactor (SMR) may be attractive in terms of land acquisition since the area of a solar receiver coupled with SMR can be smaller than with present NPPs. If small CSP become economically feasible with SMRs, the hybrid system with SMR will contribute to an increase of CSP capacity and a cost reduction of the solar energy system is consequently expected.

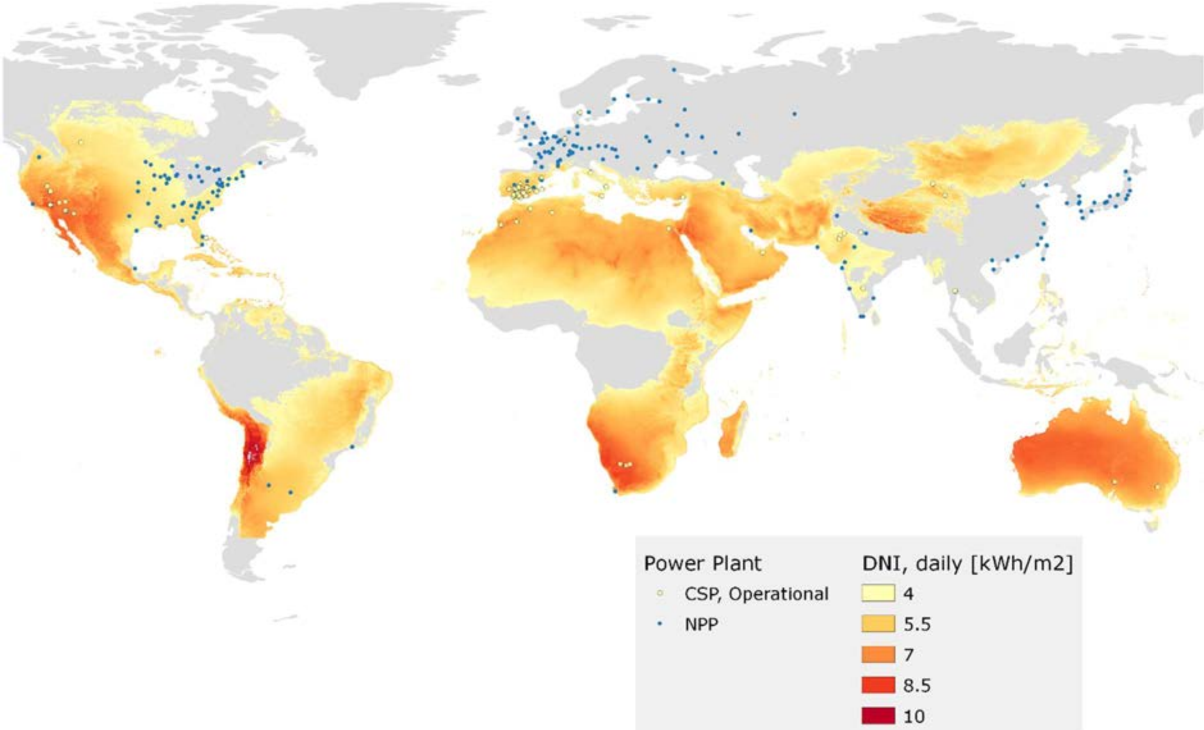

FIG. 9. The location of NPP and CSP with daily DNI [11–13].

3.4. Hybrid system with OTEC

OTEC utilizes the temperature difference of surface sea water and deep sea water with Organic Rankine Cycle (ORC) as the main method of electricity generation. OTEC may be suitable for the bottoming cycle of NPP for the following reasons:

— Many NPPs are located on coasts;
— Waste heat is constantly discharged since NPPs are usually operated in baseload;
— A large amount of waste heat is discharged from NPPs, as mentioned before.

3.4.1. System overview

The difference between the hybrid system with OTEC and sole OTEC is that the discharged circulating sea water from the NPP will heat the working fluid of OTEC at the evaporator. The temperature of discharged water from an NPP will be typically increased by 7°C or more at the condenser. Theoretically, around 60 MW_e can be produced from OTEC with the discharged heat if the thermal efficiency of ORC is assumed as 3%. Nevertheless, the combined OTEC system with the discharged heat of fossil power plants [14] or NPPs [15,16] have been investigated; there is no OTEC hybrid plant confirmed as of September 2018. The schematic diagram of an NPP hybrid system with OTEC is shown in Fig. 10.

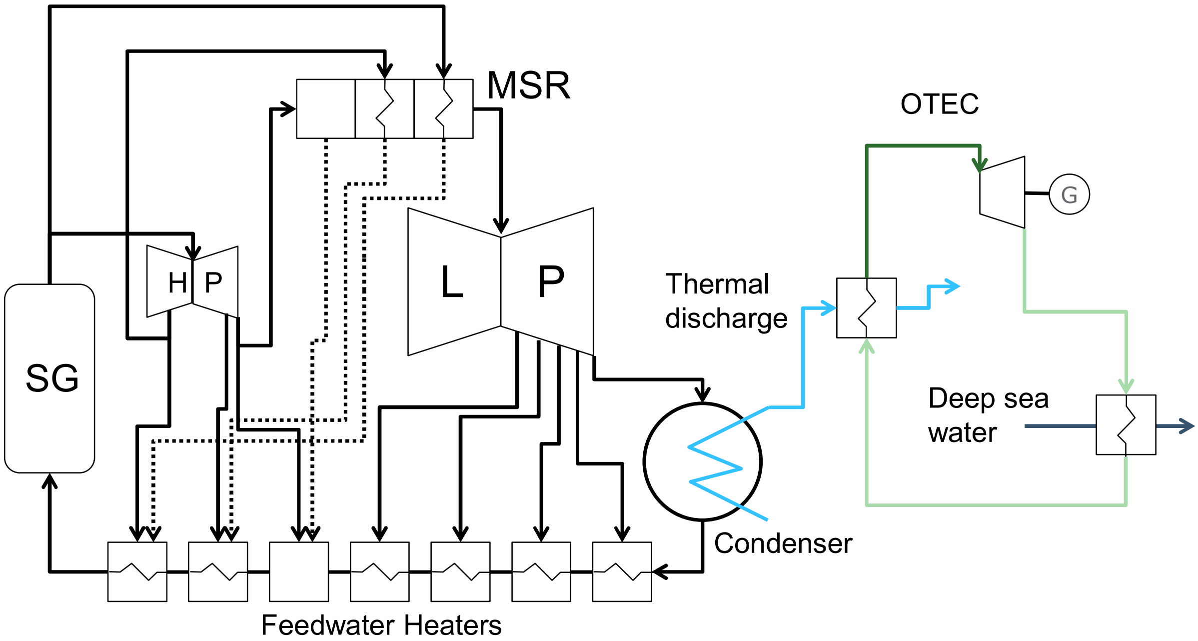

FIG. 10. Hybrid system with OTEC, closed cycle OTEC is assumed.

3.4.2. Advantages

There are some advantages gained from the higher temperature of surface sea water discharged from the NPP.

3.4.2.1. Extension of OTEC applicable region

The applicable region of OTEC will be extended with the hybrid system since the temperature of surface sea water will be increased by the thermal discharge of NPP. The temperature difference of sea water temperature between 5 m and 1000 m below surface [17] and the locations of NPPs [11] in the world is shown in Fig. 11. The submarine topography is not considered. There are two regions in the figure; the region which has temperature differences more than 20°C is suitable for OTEC. Low latitude countries with developing NPP projects seem to be suitable for OTEC hybrid systems. Another region where the temperature difference is only between 13°C and 20°C may be applicable with the proposed hybrid system since the temperature of OTEC inlet will be increased by 7°C or more.

3.4.2.2. Performance

The inlet temperature of surface water will be increased by the thermal discharge of NPP; therefore, the thermal efficiency of OTEC will be slightly increased. However, this depends not only on the temperature of discharged water but also on the design of heat exchangers.

3.4.2.3. Cost reduction of OTEC

In the proposed hybrid system, shallower deep sea water can be applied rather than that of sole OTEC in order to maintain the same temperature difference as that of sole OTEC since the thermal discharge of NPPs increase the temperature of surface water. This will contribute to reduction in OTEC's cost. For example, the temperature difference of sea water temperature between 5 m and 500 m below surface [17] and the locations of NPP [11] in the world is shown in Fig. 12. This figure shows that OTEC hybrid with NPP between surface and 500 m below can operate in almost the same area as between 1000 m without hybrid. Sharing some of the electric facilities in an NPP with the power block of OTEC may also reduce the cost of OTEC.

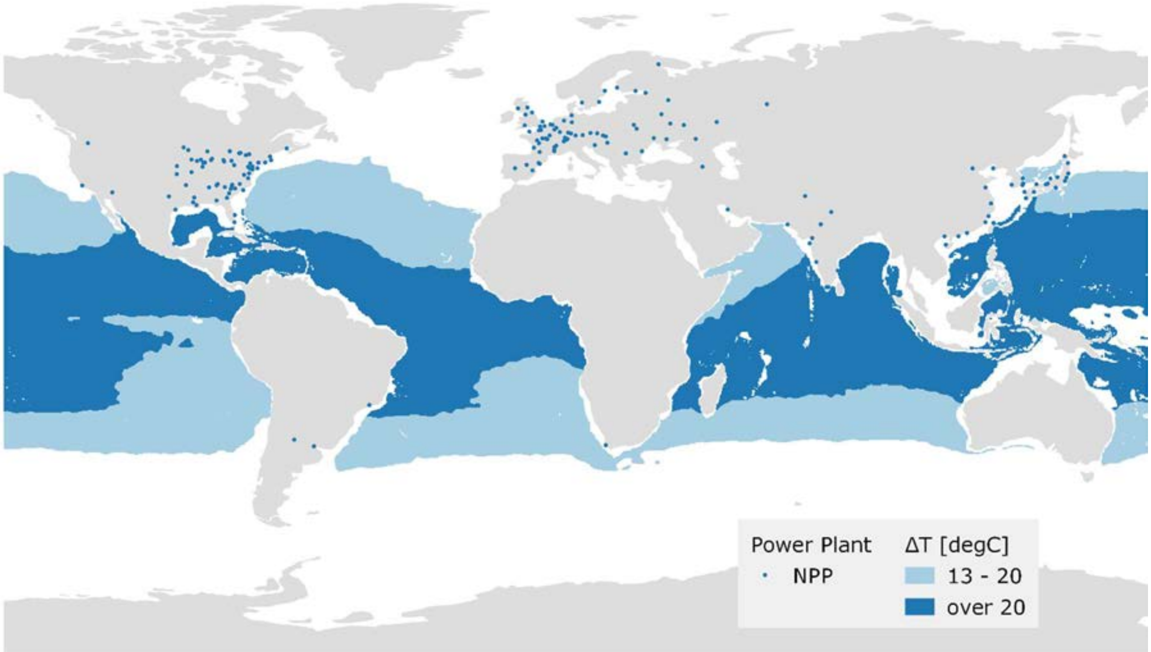

FIG. 11. Temperature difference of sea water temperature between 5 m and 1000 m below surface and locations of NPP [11,17].

3.4.3. Challenges

OTEC is under the development phase; therefore, major challenges regarding these hybrid systems are discussed in this paper.

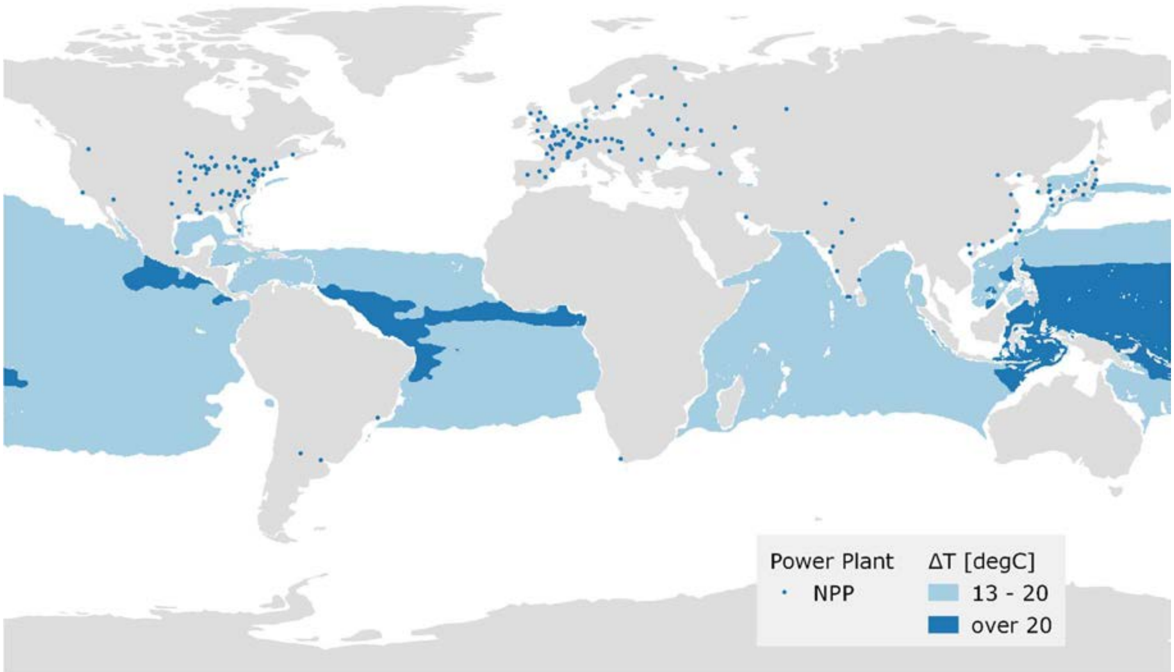

FIG. 12. Temperature difference of sea water temperature between 5 m and 500 m below surface and locations of NPP [11,17].

3.4.3.1. Circulating water system optimization

If the price of electricity is different by its source, there will be room for optimizing the entire system economically. The higher temperature of thermal discharge means a lower vacuum pressure of condenser and this causes a lower output from the NPP's view. On the other hand, the higher temperature of surface sea water will contribute to OTEC's performance. This optimization also depends on the balance of electrical capacity between OTEC and the NPP.

3.4.3.2. Installation of the evaporator

Arrangement of the evaporator at the discharge area of an NPP remains to be investigated since a large amount of discharged water will flow into the evaporator and it may affect the design of the discharge area of the NPP. Moreover, the feasibility of an evaporator scaled up for OTEC over 10 MW_e class remains unclear [18].

4. SUMMARY

Prior work has been documented for NPP and RE hybrid systems. However, some studies have not focused on the thermal characteristics of the NPP. This paper described two concepts of NPP hybrid systems with: (a) CSP which gives the thermal energy as the heating steam, and (b) OTEC which obtains the waste energy from NPP. Moreover, this 'Thermal Hub' concept can be applicable even for existing NPPs. This concept will contribute the mutual developments of renewables and nuclear energies.

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SESSION III

ROLE OF SMRs IN INTEGRATED ENERGY SYSTEMS AND COGENERATION

FLAMELESS CALCINATION OF MINERALS USING CONCENTRATED SOLAR POWER (CSP) AND HIGH TEMPERATURE GAS-COOLED REACTORS (HTGRS) — OPPORTUNITIES FOR NUCLEAR-RENEWABLE HYBRID ENERGY SYSTEMS

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Abstract

Mineral resources are depleting rapidly with little to no new large deposits exploited. Resource depletion results in increasing (often exponentially increasing) energy demands for mineral processing of lower grade ores due to the larger amount of associated gangue material. This is particularly true for energy intensive mineral calcination that accounts for some 10% of all anthropogenic greenhouse gas emissions annually. RWTH Aachen University in Germany and Tsinghua University in China developed a system for mineral calcination of minerals that uses a heat transfer fluid (HTF) for mineral calcination. The HTF can be heated using greenhouse gas lean concentrated solar power (CSP) or high temperature reactors (HTRs). Since this system makes fossil fuel combustion obsolete it was coined 'flameless'. Besides solar or nuclear, a nuclear–renewable hybrid energy system (N–R HES) approach can be desirable for flameless calcination of minerals.

1. INTRODUCTION

Material resources around the globe are depleting rapidly with little to no new large deposits exploited. Resource depletion results in increasing (often exponentially increasing) energy demands for mineral processing of lower grade ores due to the larger amount of associated gangue material. Fig. 1 shows the depletion of nickel, gold, zinc, copper, lead and silver over the last century [1].

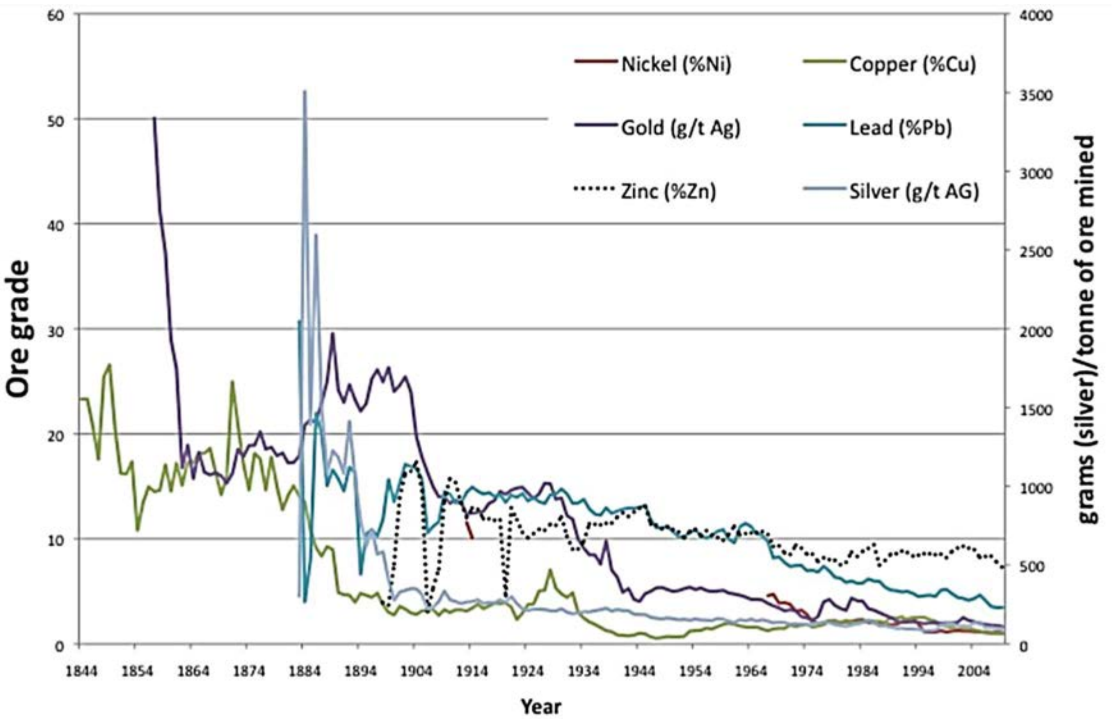

FIG. 1. Depletion of some ore grades globally.

Besides depleting ore grades, ever more critical societies demand clean and sustainable production of energy used for mineral processing. Both solar and nuclear power can provide greenhouse gas lean energy and can thus be favourable for mineral processing. Reitsma et al. [2] described how high temperature gas cooled reactors (HTGRs) can be used to provide inexpensive process heat for a number of mineral processes. RWTH Aachen University in Germany and Tsinghua University in China developed a system for mineral calcination using concentrated solar power (CSP) and HTGRs [3,4]. Since this system makes fossil fuel combustion obsolete it was coined 'flameless'.

2. FLAMELESS CALCINATION OF MINERALS

Fig. 2 depicts the 'tube in tube' helical system for mineral calcination introduced earlier. Finely ground material is mixed with superheated steam and enters the system through an injector (red) at the top of the helical reactor tube (yellow). Before entering the helical reactor tube (yellow) the mineral steam mix travels upward. On its way to the reactor tube (yellow) the mineral steam mix is pre-heated by rising exhaustion gases. The pre-heating is not sufficient for the actual calcination reaction. The calcination reaction takes place in the helical reactor tube (yellow) while the powder steam mix travels downward. Calcined granules and pure CO_2 are separated at the bottom of the system. Due to its light weight, CO_2 rises through the helical tube bundle to the top where it can be captured and safely stored. The calcined granules just drop to the bottom where they can be moved with a product hopper. Detailed description of the 'tube in tube' helical system is provided by Haneklaus et al. [3, 4].

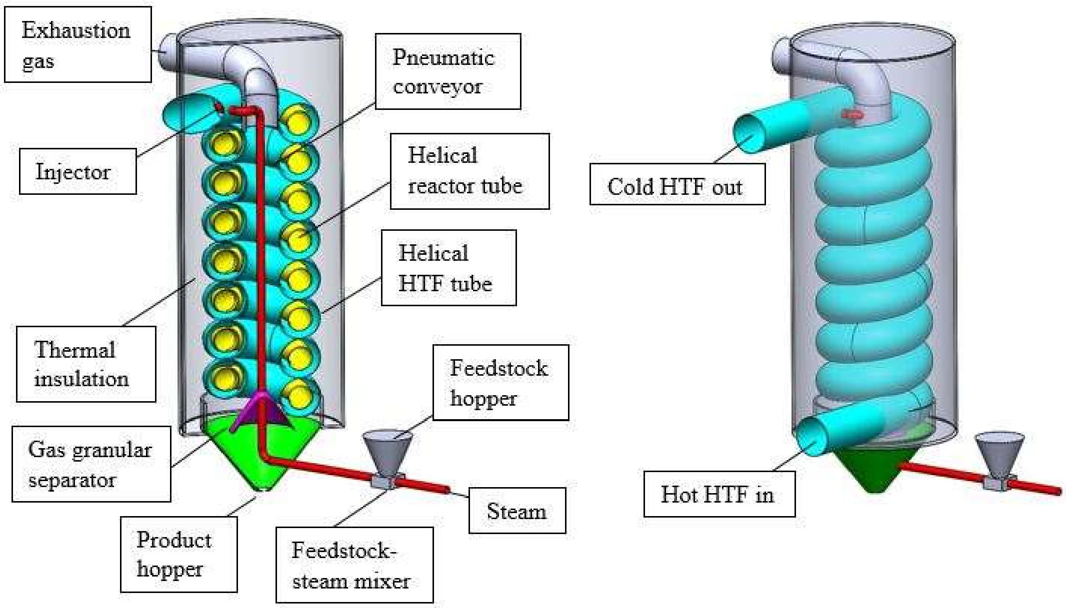

FIG. 2. System for 'flameless calcination' of minerals developed by RWTH Aachen University and Tsinghua University.

Using CSP for mineral processing is an active field of research. The proposed designs usually use concentrated solar radiation directly on a small volume of mineral feed. This way very high temperatures, well above 2000 °C, can be realized. An indirect system as proposed here, that uses a heat transfer fluid (HTF) does not reach the high temperatures. The system does, however, allow for much larger mineral throughputs. It may thus be interesting for minerals where lower calcination temperatures (< 1000 °C) are sufficient. This is for instance the case for some phosphate rocks.

The flameless calcination system with 'tube in tube' reactor could be powered using CSP only, HTRs only or a hybrid system comprising both power sources. Fig. 3 shows simplified schematic overviews of the two hypothetical plant configurations with CSP only (Fig. 3a) and HTRs only (Fig. 3b) as well as a conventional rotary calcination kiln (Fig. 3c) powered with natural gas. The CSP system on top is motivated by the Gemasolar power plant recently commissioned in Spain that has a receiver thermal power of 120 MW_{th} [5,6]. The flameless calcination system with HTRs (middle) is motivated by the

HTR-PM demonstration plant currently under construction in Shandong Province, China that will provide 2 × 250 MW_{th} [7,8].

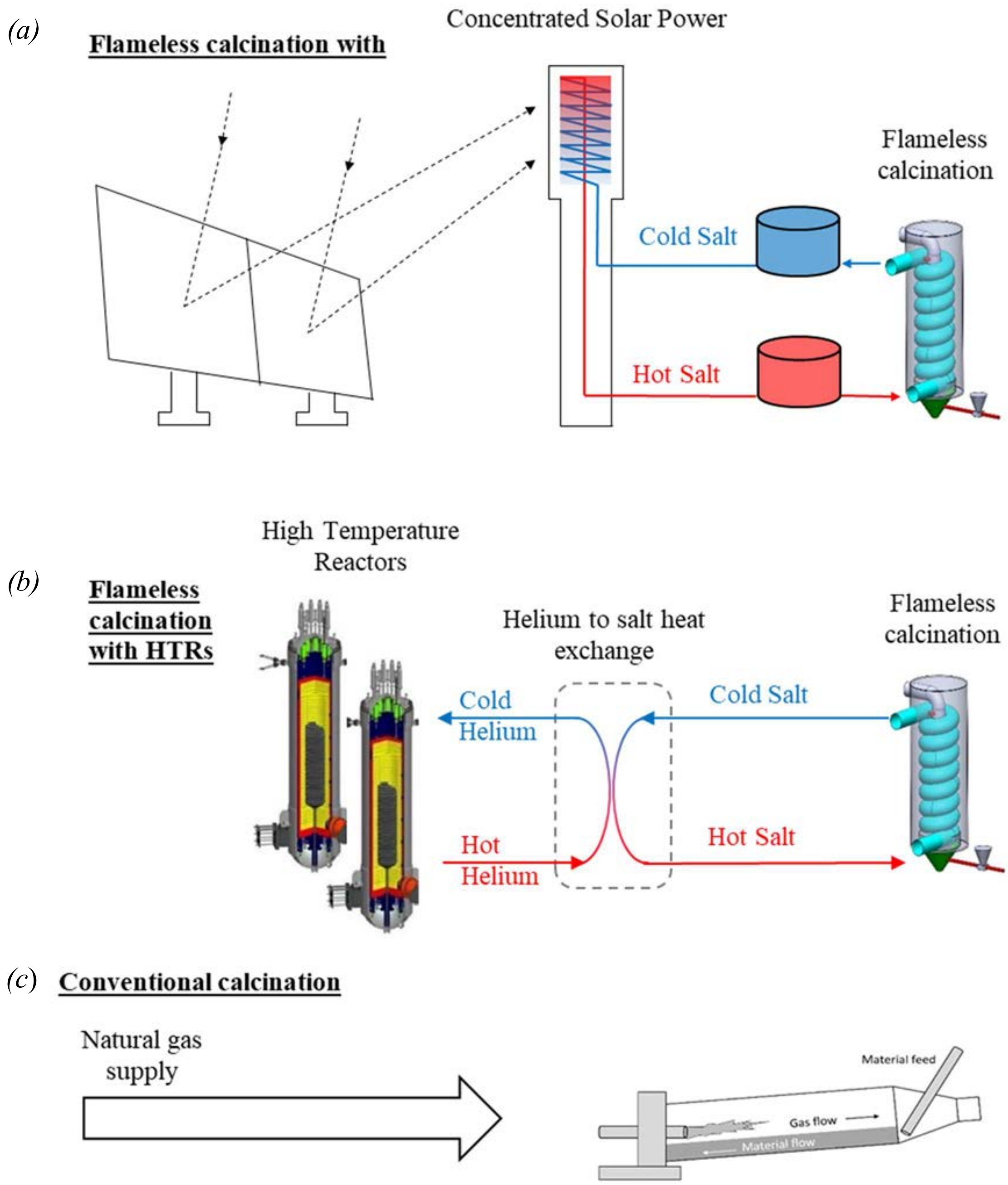

FIG. 3. Schematic overview of the three hypothetical plant configurations considered: (a) flameless calcination system with CSP, (b) flameless calcination system with HTRs and (c) conventional natural gas fired calcination system.

The technical feasibility of such a system has yet to be proven. Despite the investigations done by RWTH Aachen University and Tsinghua University great work is done by Calix Ltd. in Australia . The successful experiments from Sceats et al. [9] for Calix Ltd. resulted among other things in the Leilac ("Low Emissions Intensity Lime and Cement") project [10] that received more than 10 million Euro funding from the EU to build a prototype calcination furnace that promises greatly reduced CO_2 emissions. The project shows the tremendous interest of the European mineral processing industry as well as the EU in cleaner mineral processing technologies.

Based on the heat requirements for flameless calcination using the tube-in-tube helical system (3.6 MW_{th} in total; 2.6 MW_{th} for 1.45 kg/s calcite that needs to be heated to 600-750 °C and 1.0 MW_{th} for 0.05-0.5 kg/s superheated steam at 0.02-0.3 MPa) BrivaTech Consulting designed an adequate cogeneration system for another EU project with one HTGR that is depicted in Fig. 4 [11].

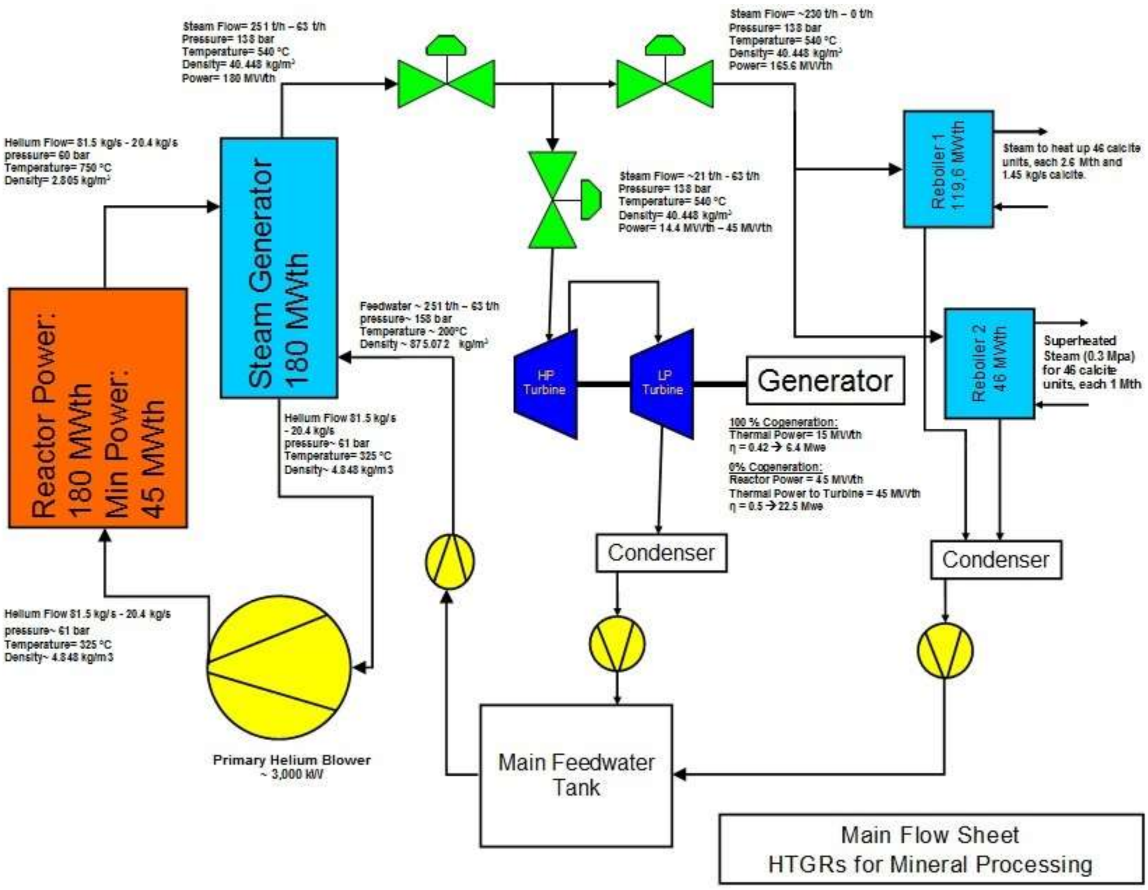

FIG. 4. Layout of a HTGR cogeneration system for flameless phosphate rock calcination (source: BriVaTech).

A HTGR with 180 MW_{th} will be sufficient to provide high temperature process heat and superheated steam for up to 46 calcination units. Electricity is only generated for the cogeneration system itself. Different configurations with less calcination units and more electricity production could of course be considered.

3. NUCLEAR–RENEWABLE ENERGY SYSTEMS FOR FLAMELESS PHOSPHATE ROCK CALCINATION

Since both calcination systems discussed here using CSP and HTGRs work with the same HTF potential advantages of using a hybrid system could apply [12–14]. Specifically, both CSP and HTGR could be coupled to a Nuclear–Renewable Hybrid Energy System (N–R HES) that can take advantage of synergies resulting from such a coupled configuration.

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TR_EVOL: A FUEL CYCLE SCENARIO CODE FOR ENERGY POLICY PLANNING

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Abstract

A renewable–nuclear energy mix is one of the best options to meet future energy requirements assuring deep decarbonization. Searching for a sustainable solution, numerous nuclear fuel cycle scenarios have been proposed to cope with different alternatives; however, the presence of renewable energies in the mix, as well as the introduction of new technologies for reactors and industrial processes, make the existing codes to require new capabilities. The TR_EVOL code, developed by CIEMAT, is one of the few existing tools capable of estimating key indicators in nuclear fuel cycle scenarios, assessing the presence of renewable energies in the mix. The knowledge of these indicators, along with other variables of the defined energy scenarios, can provide a consistent way for Government, industry and regulators, to plan energy policies for a country. In this paper, TR_EVOL is presented, providing a general description of the code. Furthermore, a fuel cycle assessment and a cost analysis are performed in order to demonstrate TR_EVOL capabilities. A light water reactor fleet representative of Spain has been chosen to perform the fuel cycle assessment. Results show that the lifetime of the reactors has an impact in the possible reduction in the Pu amount. Some scenarios show a shortage of Pu available for mixed uranium–plutonium oxide fuel fabrication coming from the reprocessing of UO_2 spent fuel. Regarding the cost analysis, generation costs of two fuel cycle scenarios show satisfactory results and the estimation of the backend cost results are highly acceptable, taking into account the existing difficulties.

1. INTRODUCTION

The estimated increase in world population to more than 9700 million people by 2050 [1], along with the need for sustainable development to reduce CO_2 emissions to combat climate change (the main environmental concern in the next 50 years [2]), compels to find energy sources that can meet future needs. They must produce energy for a long time without harming future generations, so that the environment is respected and production is economically viable, safe and guaranteed regardless of location or geopolitical conflicts. Renewable energies are the key solution to address these challenges, however, due to their high degree of availability volatility in a very short time [3], they cannot operate without the help of other baseload energy producing technologies capable of load following. Nuclear energy is a competitive and reliable, emission free power source that meets all the mentioned criteria. Consequently, a renewable–nuclear energy mix is one of the best options to meet future energy requirements assuring deep decarbonization.

Searching for a sustainable solution, numerous nuclear fuel cycle scenarios have been studied to handle different alternatives including combinations of technologies and processes from mining to proper final disposal. These scenarios can be represented by a small number of them [4,5], emphasizing different purposes or points of view: competitiveness, minimization of nuclear waste, optimization of the use of natural resources, etc. Different fuel cycle codes have been developed to cope with the complex problem of assessing current or advanced nuclear fuel cycles and their potential to achieve the proposed objectives. However, the presence of renewable energies in the mix, as well as the implementation of new advanced technologies and processes, makes the existing codes to require a profound upgrade to adequately evaluate the transition from current operations to more advanced state with sustainable properties [6,7].

The study of fuel cycle scenarios includes the analysis of various technologies and reactors in a wide period of time. The use of the resources, their evolution with the irradiation in nuclear power plants and the generation and later management of nuclear waste are taken into account in these analyses. In particular, the isotopic composition of all the materials in every component of the fuel cycle is considered (essentially uranium, plutonium, minor actinides and fission products). Besides, economic efficiency is one of the three pillars of sustainable development along with environmental and social dimensions [8]; while competitiveness is a relevant indicator insofar market prices reflect the full costs for society of a given product or activity. The economic analysis of the nuclear fuel cycle scenario is usually done by means of the Levelized Cost of Electricity (LCOE), which is defined as the long term breakeven price that investors should receive to cover all their costs, including an acceptable return on investment as expressed by the discount rate [9]. This cost is usually expressed as cost divided by a unit of generated energy, typically in cents/kWh, $(€)/MWh, etc. The knowledge of these indicators (use of resources, waste generation, costs, …), along with other variables of the defined energy scenarios, can provide a consistent way for government, industry and regulators to plan energy policies for a country.

One of the few existing tools capable of performing these analyses is TR_EVOL [10], a code developed at CIEMAT, Spain, with the aim of achieving the requirements of research in the field of transition/dynamic fuel cycle scenarios, by being able to simulate diverse fuel cycle scenarios, and provide useful indicators and conclusions. The code has been extensively validated in several OECD/NEA benchmarks. The aim of this paper is to present TR_EVOL, providing a general description in Section 2 and demonstrating its current capabilities in fuel cycle assessment and cost analysis in Sections 3 and 4, respectively.

2. TR_EVOL

The transition evolution code TR_EVOL is able to simulate diverse nuclear power plants (among them, light water reactors, fast reactors, and critical or subcritical systems can be emphasized), having different types of fuels such as UO_2, MOX, metal fuel. The associated fuel cycle facilities can also be simulated by the code, including fuel fabrication plant, the enrichment plant, reprocessing facility, interim or waste storage, and final geological disposal. The load following due to the presence of renewable energies in the mix can be also simulated by TR_EVOL.

Nuclear reactors can be simulated in two different ways: as single averaged macroreactors (reducing the computational needs) or individually each reactor of the fleet (requiring hence larger computer resources).

The irradiation is simulated in TR_EVOL by means of ORIGEN 2.2 (Isotope Generation and Depletion Code) [11], which has been completely incorporated within TR_EVOL in order to optimize the data transfer between modules and increase computational speed. This irradiation considers the detailed evolution of the fuel isotopic composition and nuclear materials with burn-up. The ORIGEN reference cross section libraries can be used for current reactors, while for other more complex designs, libraries specifically created with EVOLCODE 2.0 [12] (CIEMAT, Spain) can be used. More details about the physics and capabilities of TR_EVOL can be found in [6,10,13].

TR_EVOL also includes a module for economic assessments which is able to provide the Levelized Cost of Electricity. This module obtains the economic information using the TR_EVOL mass balance output file and unit costs introduced by the user beforehand. Four types of costs are considered by this module:

— Investment cost: the overnight cost of the plant, interest rates, payback periods, and construction periods are considered as part of this cost.

— Fuel cost: this cost is calculated using parameters such as raw materials, enrichment, conversions, and fabrication in case of UO_2 fuel, or a fixed cost by kg in case of MOX fuel for LWR, fast reactors or Accelerator Driven Subcritical systems. If reprocessing is needed before fuel fabrication, the reprocessing cost is implicitly included as part of this cost.
— Operation and maintenance (O&M) cost: this cost is given per unit of installed capacity (€/GWe).
— Waste management cost: this cost includes fixed and variable costs from facilities or processes like shaft, galleries, canisters, and glasses (which are limited by heat production), and the decommissioning and dismantling cost as a percentage of the overnight cost (DDD). It is the sum of interim and final disposal cost.

3. FUEL CYCLE ASSESSMENT

The aim of this work [14] is to find the key indicators with upmost importance for the implementation of reprocessing in a medium sized light water reactor (LWR) fleet of the size of Spain. As it was the case of this country, an approximately constant energy demand has been considered (54.9 TWh in 2014, according to [15]). The inventories of the Spanish nuclear power park have been taken into account as well. The conclusions reached in this assessment can also be considered valid for other countries with similar nuclear energy production, such as Belgium or Sweden.

The scenarios of interest here have been divided into two different groups, depending on its lifetime. Scenarios considering a lifetime of 40 years have been labelled with '40'. For this lifetime, the scenarios have been labelled as follows:

— The once through strategy, used as reference scenario, is labelled scenario 40-ONCE.

— Scenario 40-PART refers to the case where there is reprocessing but only a part of the SF is reprocessed, consisting on the amount required to obtain the Pu to fabricate the maximum possible amount of MOX to be burned in the fuel cycle.

— Scenario 40-FULL refers to the case where all the spent fuel is reprocessed. The main objective of this scenario is to avoid final disposal. Thus, only high level waste from (partially) closed cycles other than SF (high level waste reprocessed (HLWr)) will be disposed of in this scenario. Note that surplus Pu and RepU separated at the end of the fuel cycle scenario (EOC) and with no use for the scenario itself can be valued as assets for their use as fuel by other fuel cycle scenarios or countries in the case of economic studies.

Considering a lifetime of 60 years, a second group of scenarios has been studied. These scenarios are labelled with '60' and follow the previous subdivision: scenarios are 60-ONCE (once through, reference scenario), 60-PART (partial reprocessing), and 60-FULL (full reprocessing).

3.1. Hypotheses

The key assumptions used in the modelling of fuel cycle scenarios for Spain are as follows:

(1) The information on the Spanish nuclear fleet performance was taken from the Power Reactor Information System (PRIS) [16] up to the year 2012. Beyond 2012, a projection of the energy production considering the scenario assumed decommissioning dates has been considered, as shown in Fig. 1. The total energy estimations for 40 and 60 years for the whole cycle are 2178 TWh_e and 3277 TWh_e, respectively.
(2) For the reactors with 40 years of operation, an averaged value of the fuel burn-up of 40 GWd/tU has been considered. For reactors with 60 years of operation, 40 GWd/tU was used for the first 40 years and 50 GWd/tU for the additional 20 years.
(3) Each PWR and BWR reactor was simulated separately in each scenario, excepting Vandellós I which was not considered in the simulations.

(4) A minimum period of five years of cooling time before reprocessing has been taken into account for the SF. Efficiency values of 99.9% for reprocessing and 100% for fabrication have been considered.
(5) In scenarios with reprocessing, and according to an average of the current technology status [17], all reactors use MOX in 1/3 of the core since year 2016 until decommissioning.
(6) In scenarios with reprocessing strategies, uranium is recovered from the SF and then re-enriched to fabricate fresh UO_2-R fuel. The fuel specifications are shown in Table 1 [18]. Note that the final enrichment for RepU fuel has to be larger than for UO_2 fuel from natural uranium (NatU) to compensate the amount of ^{236}U, which acts as poison. This enrichment is a result of the simulation, not a hypothesis.

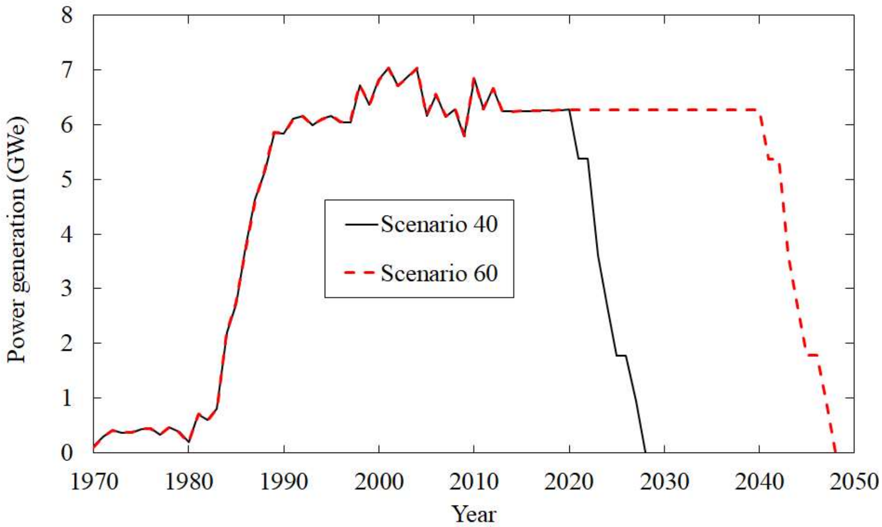

FIG. 1. Power generation *(scenarios 40 and 60).*

TABLE 1. FUEL SPECIFICATIONS

	TYPE	40 GWd/tU/50 GWd/tU
UO_2	Enrichment from NatU (UO_2)	4.0%/4.5%
	Enrichment from RepU (UO_2-R)	4.5%/4.9%
	Tails	0.2%
MOX	Fissile enrichment (Pu+^{235}U)	8.85%

3.2. Results and discussion

The fuel requirements for the different scenarios are contained in Table 2. As shown in the table, scenarios 40 with reprocessing are able to provide more ‘fresh fuel’ coming from the SF acting as a resource. In particular, MOX fuel and re-enriched RepU can be fabricated. 3780 t of UO_2-SF are reprocessed in these scenarios providing savings in the scenario of more than 8000 t of NatU. Additionally, a certain amount of depleted uranium (DepU) is also created from the RepU re-enrichment in both scenarios 40 with reprocessing. This value reaches around 4000 t. The reprocessing of UO_2-SF fuel (occurring between years 2014 and 2020) provides the Pu for MOX fabrication. In year 2023, the decay period for cooling at the reactor pool of the irradiated MOX and UO_2-R fuels finishes, so this irradiated fuel (MOX-SF and in UO_2-R-SF) becomes available for reprocessing. Finally, in scenario 40-FULL, the remaining SF is reprocessed at EOC.

TABLE 2. FUEL REQUIREMENTS FOR THE DIFFERENT SCENARIOS [14]

PARAMETER	UO_2 FUEL (tU)				MOX FUEL (tHM)		
	TOTAL FUEL MASS	FROM NatU	FROM RepU	NatU REQUIRED	FUEL MASS	Pu REQUIRED	DepU REQUIRED
40-ONCE	6810	6810	0	50 900	0	0	0
40-PART/40-FULL	6363	5699	664	42 600	447	38.7	408
60-ONCE	9390	9390	0	74 800	0	0	0
60-PART/60-FULL	8094	6939	1155	55 300	1296	112	1184

Table 2 also contains the fuel requirements for scenarios '60'. In scenarios 60-FULL and 60-PART, the table shows that 112 t of Pu are needed to fabricate 1296 t of MOX fuel. Almost 20 kt of natural uranium is saved by the reutilization of Pu in these scenarios. Unfortunately, the Pu available by reprocessing all the UO_2-SF is not enough to fabricate this amount of MOX fuel when it is needed, as shown in Fig. 2 beyond year 2029, when the 'total Pu needed' exceeds the amount of 'Pu in irradiated UO_2'. Using only this Pu, the scenario would be limited to approximately half of the power generation shown in Fig. 1. A total of 845 t of MOX fuel may be fabricated considering only the reprocessing of this UO_2-SF. On the other hand, the scenario is able to provide other sources of Pu by means of the UO_2-R-SF and the MOX-SF. With the Pu in these streams, the 'total Pu needed' demands for fuel fabrication would be satisfied. However, this study does not consider the reprocessing of these SF to be available at these dates but at EOC instead [14]. Hence, the existence of an external supplier borrowing the needed Pu has been assumed to solve this issue. This borrowed Pu would be returned at EOC, when the reprocessing of the SF needed to obtain it would be done. Two options, renamed scenarios 60-PART-1 and 60-PART-2, have been considered to obtain the Pu to be given back at EOC:

- Scenario 60-PART-1: all the UO_2-SF and UO_2-R-SF are reprocessed, plus some of the MOX-SF.
- Scenario 60-PART-2: the Pu mass borrowed is obtained from the reprocessing of all the UO_2-SF, plus the MOX-SF (more Pu enriched than the UO_2-SF).

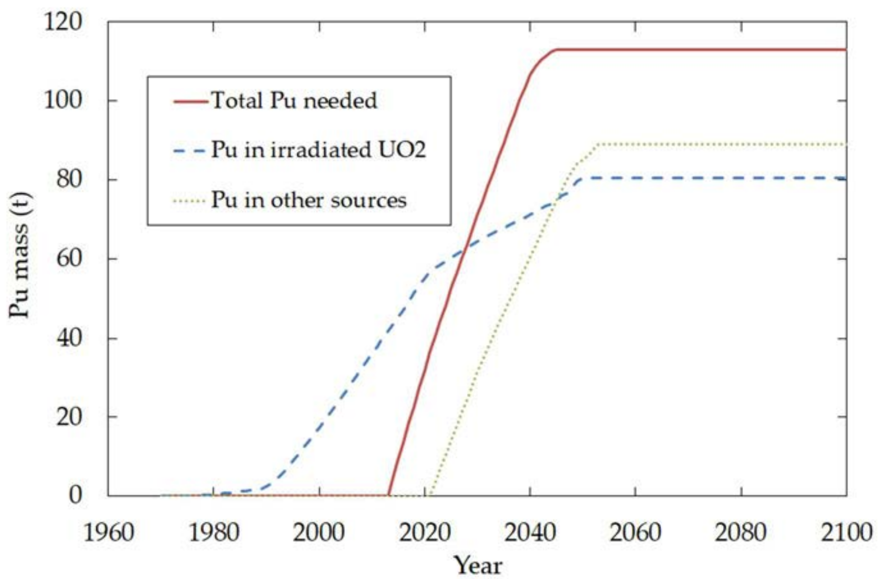

FIG. 2. Total Pu amount by SF source for scenario 60.

Additionally, the RepU re-enrichment also provides in both cases around 5700 t of DepU.

Concerning the material balance at EOC, the SF in scenario 40-ONCE contains around 68 t of Pu. Additionally, the reprocessing of some nuclear fuel from José Cabrera and S. M. Garoña until year 1983 provides also small quantities of Pu and generates a small amount of HLWs (as shown in Table 3). Also, 65 t of separated RepU are created in scenario 40-ONCE. Scenario 40-PART allows a small reduction from 68 t of Pu to around 51 t of Pu at EOC. Differently, scenarios 60 show a different behaviour where a significant reduction of around 50% in the Pu amount can be seen. In particular, scenario 60-ONCE has ~93 t of Pu in the spent fuel, and it is reduced down to 44 t for Scenario 60-PART. Additionally, Table 3 shows the SF and HLWr mass to store in the final disposal facility (FD). In the open cycle scenarios 40-ONCE and 60-ONCE, the SF is considered as waste to be stored in a final disposal; the value of 2.5 t of HLWr comes as abovementioned from the mass reprocessed for some nuclear power plants until year 1983 (~68 t). Differences between scenarios 60-PART-1 and 60-PART-2 come from the priority given to the material reprocessing to obtain the Pu to be given back to the external supplier. It can also be seen that, for scenarios with reprocessing, the mass of material to be stored in the FD is significantly reduced.

TABLE 3. WASTE MASS TO BE STORED IN THE FINAL DISPOSAL FACILITY

SCENARIO	MASS (t)	
	SF	HLWr
40-ONCE	6742	2.5
40-PART	3030	141
40-FULL	0	254
60-ONCE	9322	2.5
60-PART-1	820	329
60-PART-2	1721	295
60-FULL	0	369

Table 4 shows the SF mass to be reprocessed at EOC for those scenarios with extra reprocessing at EOC. Scenario 60-PART-2 has the smallest amount of mass to be reprocessed at EOC because the Pu content in the MOX-SF is five times higher than in UO_2-SF.

TABLE 4. FUEL REPROCESSED AT END OF FUEL CYCLE SCENARIO (EOC)

SCENARIO	MASS REPROCESSED (t)
40-FULL	3030
60-PART-1	1631
60-PART-2	730
60-FULL	2451

4. COST ANALYSIS

To demonstrate TR_EVOL cost analysis capabilities, scenarios defined in the EU funded project 'ADS and fast reactor comparison study in support of Strategic Research Agenda of SNETP' (ARCAS) [19] have been used.

The ARCAS main document for economic assessments [20] has been taken as reference for this evaluation. This document analyses different strategies considered in the project for a nuclear fuel cycle scenario with zero net production of MA from the point of view of economics. CNRS and NRG have provided two different economic models and hypotheses for the scenarios proposed. These scenarios include the the EFIT concept [21], which has been used as the accelerator driven system (ADS), and two different types of fast reactors (FR) with homogeneous and heterogeneous configurations. The document contains the final value of the LCOE per reactor type so in this work, the comparison will be made here for the reactor type (FR and ADS technologies) cost only.

The economic model and hypotheses provided by NRG have been used in this work to analyse the scenarios for its similarities with the ones implemented in TR_EVOL. One scenario with ADS and other with FR homogeneous configuration have been selected for their economic analysis.

The features and parameters for the FR and ADS proposed by ARCAS have been used for comparing the costs. Only the investment cost, the fuel cost and the O&M cost have been considered in this work. For the backend cost a more detailed analysis of these costs has been done and it will be shown in Section 4.2.1.

4.1. Hypotheses

The following hypotheses [20] have been considered in this study:

(1) FR simulation: the homogeneous configuration has been for estimating the FR cost. This scenario has a 70% of the energy provided by FR and 30% by PWR- UO_2 fuel. In this scenario, the FR fleet includes in its fuel all the MA generated in the scenario, coming both from their used fuels and from the PWR stratum.

(2) ADS simulation: for the ADS, the scenario states that 97.4% of the energy is produced by a first stratum composed of PWR-UO_2 fuel and the other 2.6% is provided by the ADS stratum. The ADS is designed to be a MA burner. As a consequence, it has a large MA burning capacity (estimation about 112.5 kg/TWh_e). Although the share of electricity produced in ADS is small, the amount of ADS systems in the park is still quite significant, due to the small power per unit, of 400 MW_{th}.

4.2. Results and discussion

The results, published in Ref. [10], have been summarized in Table 5. They include as abovementioned the estimations for the investment cost, the fuel cost, the O&M cost and total LCOE, which are very similar between TR_EVOL and ARCAS models, with differences lower than 3%, for both reactor types FR and ADS.

TABLE 5. FR AND ADS RELATIVE ERRORS IN THE ESTIMATION COSTS USING TR_EVOL AND ARCAS MODELS

COST COMPONENT	RELATIVE ERROR	
	FR	ADS
Capital	-0.5%	-0.7%
O&M	1.1%	0.6%
Fuel	2.6%	1.4%
LCOE	0.3%	-0.3%

This comparison verifies the correct implementation of the economic model for the three components of the LCOE analysed (investment costs, fuel cost and O&M cost) and hence for the total LCOE. The backend cost analysis is shown in the following section.

4.2.1. Backend cost

4.2.1.1. Decommissioning and dismantling cost

The cost of decommissioning and dismantling is usually expressed as a percentage depending on the overnight cost of the power plant [22]. For the TR_EVOL model a 15% of the overnight cost has been selected as an averaged of the information published. No cross check has been hence made for this cost.

4.2.1.2. Interim storage cost

The model implemented in TR_EVOL for the interim storage cost is divided into a fixed cost (FC), which does not depend on the mass to store, and a variable cost (VC), depending on the mass to store. The FC of the interim storage facility is divided into construction cost and dismantling cost. The variable cost is formed by a number of canisters times the storage unit cost.

In order to value these costs items, published data have been used. The Swedish interim storage [23–25] (wet storage) and the Spanish interim storage [26,27] (dry storage) have been considered.

The main fixed and variable costs have been created (Table 6) using the published data from bibliography for their implementation in the TR_EVOL model. However, given the scarcity of information about real interim storages, the results of the model have not been verified. Hence, it is assumed that these values can be applied for a general concept of interim storage when no other referenced values are available.

TABLE 6. ID COST SUMMARY IN M€ [10]

ITEM	SWEDISH ID	SPANISH ID	AVERAGE
FIXED COST			
Investment cost	345	503	424
Decomm. Cost	65	65	65
Total	410	568	489
VARIABLE COST			
O&M unit cost (M€/t)	0.184	0.126	0.155
O&M unit cost (M€/canister PWR)	0.342	0.234	0.290
O&M unit cost (M€/canister BWR)	0.397	0.272	0.335

4.2.1.3. Final disposal cost

In order to provide the unit costs necessary to assess any generic FD cost in TR_EVOL, the following analysis was made. Again, given the scarcity of information, these values might only serve as a first estimation. The information presented in bibliography (for FD in open cycle [25,26,28,29] and for partially closed scenarios [30,31]) has been used for the analysis. This information includes data about the SF mass generated by the cycle and its estimated FD cost and has been provided by the companies responsible for the development and construction of these facilities.

The TR_EVOL model for the FD costs includes a fixed cost and a variable cost. The fixed cost represents the sum of the overnight cost for the FD, the overnight cost for the encapsulation plant (EP), and the decommissioning cost of both. Besides, the variable cost can be described as follows:

$$Variable\ cost = VC\ (\mathrm{FD}) + VC\ (\mathrm{EP}) + GC\ (\mathrm{FD}) \tag{1}$$

where:

— VC (FD): the O&M cost of the FD includes storing and conditioning of the canister to be stored.
— VC (EP): the O&M cost of the EP includes the cost of the fabrication of the canisters and of the encapsulation process.
— GC (FD): gallery length cost for the FD, expressed as a fixed unit cost per gallery length (GL).

The estimation of GC depends on different factors which derive from the magnitudes found in bibliography. These factors include the mass to store, the number of canisters (NOC) to store and their dimensions. Additionally, the number of canisters depends on the fuel type and the number of the SF assemblies that can be introduced in each canister. The GC for FD, as a cost per km of gallery, can be obtained solving the following expression. For this process, the fixed costs and the other unit costs have been taken from the bibliography for the Spanish, Swedish and Finnish FD, or calculated from the referenced data:

$$FD\ cost = FC + VC = FC + NOC \times \left(VC\ (\mathrm{EP}) + VC\ (\mathrm{FD})\right) + GC \times GL \tag{2}$$

Solving this expression for GC, its unit cost can be obtained as an averaged value of around 19.7 M€/km. Other generic values for the TR_EVOL model are presented in Table 7.

TABLE 7. SUMMARIZED GENERIC COSTS AND PARAMETERS FOR FD MODEL [10]

ITEM	COST
Fixed cost (including EP and decomm.)	2130 M€
Gallery length cost per km	19.7 M€
Encapsulation cost per canister	0.203 M€
Management/conditioning cost (HM and HLW)	0.042 M€
Mass per assembly	465 kg
HLW mass per Universal Canisters-vitrified (UC-V)	56 kg
Canister length + separation	6.6 m
UC-V length + separation (w/o encapsulation)	1.8 m

The comparison of the FD costs for the different open cycle scenarios with published data and the results obtained by TR_EVOL model is shown in Table 8. The relative difference between both sets of results are quite satisfactory, hence it can be concluded that the model for a generic FD developed in TR_EVOL can describe correctly the cost of the FD.

To explore the model representativeness, the Canadian FD design, which has the biggest capacity of the world with almost 200 000 t of HM, has been used to check the unit costs estimated above with the data of the other countries' FD. The model provides a result with a relative difference of only 2.4% regarding the referenced data. This result is fairly accurate although some information was missing like the dimension of the canister (a canister length of 4.6 m plus a separation between canisters of 2 m have been used in the GL estimation), possibly causing compensations.

Once the model has been validated for the open cycle, it has been explored if it can be also applied to other fuel cycles, in particular those with partial closure of the cycle by means reprocessing strategies. For that, two fuel cycle scenarios with partial reprocessing strategies (Switzerland and France) have been assessed. The relative difference between the FD cost obtained with TR_EVOL and from the bibliography is shown in Table 9.

TABLE 8. FD COST FOR OPEN FUEL CYCLE SCENARIOS [10]

COUNTRY	MASS (tU)	REFERENCED COST (M€)	TR_EVOL COST (M€)	RELATIVE DIFFERENCE
Finland	5500	3330	3239	2.7%
Spain	6765	3450	3475	1.1%
Sweden	9471	3575	3814	6.6%
Canada	192000	14167	13826	2.4%

TABLE 9. FD COST FOR SCENARIOS WITH PARTIAL REPROCESSING [10]

COUNTRY	REF. COST (M€)	TR_EVOL COST (M€)	RELATIVE DIFFERENCE
Switzerland	3020	2780	7.9%
France	13981	12409	11.2%

Switzerland plans to reprocess around one third of its 3400 t of SF generated. With this boundary condition, the projected cost is 3020 M€. The TR_EVOL model has been applied considering the documented material to manage. This material includes 2200 t of UO_2 SF and 52 t of HLW generated from the reprocessing of 1200 t of UO_2 SF. The relative difference between both values is 7.9%, fairly close.

On a second check, the French FD case has been simulated following the information and assumptions from the International Panel of Fissile Materials [30]. This reference states that at the end of the scenario 17600 t of UO_2 and 4800 t of MOX are placed along with 1320 t of HLW from the reprocessing of 36100 t of UO_2 (instead of storing 58300 t of UO_2 for a hypothetical open cycle strategy). Table 9 shows that the relative difference between the referenced data and the value calculated by TR_EVOL model is fairly small, of about an 11%.

It has to be noted that the TR_EVOL model has been applied to more or less well documented fuel cycle scenarios, where the number of packages to be stored was already published. However, this model is also usable for dynamic cases, that is, for those fuel cycle scenarios where the number of packages is not documented, or it is a result of the simulation. It has been proven that the TR_EVOL model is able to estimate the final disposal cost for any fuel cycle, considering any repository design, providing good values with a small bias for open cycle scenarios and relatively small for scenarios with reprocessing.

5. CONCLUSIONS

While renewable energies are the key solution to address climate challenges and future energy needs, other baseload energy producing technologies capable of load following are necessary to operate in conjunction with renewable technologies due to their high degree of availability volatility. Nuclear energy meets all the necessary criteria, therefore a renewable–nuclear energy mix is one of the best options to assure energy requirements significantly reducing emissions.

Versatile computational tools that can help government, industry and regulators to make decisions regarding national energy policy are needed. The transition evolution code TR_EVOL, developed at CIEMAT, is one of the few tools capable of performing fuel cycle and cost analysis taking into account the presence of renewable technologies in the energy mix. A general description of the code has been provided and its current capabilities in fuel cycle assessment and cost analysis have been demonstrated.

The fuel cycle assessment shows that although none of the scenarios are able to consume all the Pu generated in the fuel cycle scenario, the reduction in the Pu amount is significant for scenarios 60, with around a 50% reduction for Scenario 60-ONCE. On the other hand, the reduction in the Pu amount is smaller in scenarios 40 (around a 25%). Additionally, for scenarios 60, the assessment shows a scenario break, that is, there is a moment when the Pu for MOX fuel fabrication coming from the reprocessing of UO_2-SF is not available. This issue has been solved assuming thar there is an external supplier which borrows around 32.4 t of Pu, needed in the scenario, and recovers its Pu at EOC. This issue could be also solved assuming that the technology to reprocess the UO_2-R-SF and the MOX-SF (other sources of Pu that could provide the Pu demands on time) is available when needed, but in this work it has been assumed that it is only available at EOC.

Regarding the cost analysis, the TR_EVOL model for the estimation of the investment cost, the fuel cost and the O&M cost was verified against the results provided by the ARCAS European project. Additionally, the cost of the energy generation in two advanced scenarios, one involving SFR and other with ADS, was evaluated. The relative differences between referenced and estimated data results were rather small in both cases (less than 3% of difference regarding ARCAS/NRG calculations). Moreover, a specific economic analysis was carried out to verify the procedure for the estimation of the Back End costs, in particular including the interim and final disposal costs. Published data was used to fix on a first step the model parameters to use when there is no additional available information about these cost types. Besides, a special methodology has been developed to estimate the gallery length, taking into account the different waste forms to be stored: spent fuel of different fuel types, vitrified high level waste, etc. The verification of the final disposal cost has also been achieved, finding a maximum value of the relative difference of 7% in the comparison in a once through scenario and a maximum value of around 11% in a final disposal of a fuel cycle scenario with a reprocessing strategy. Given the significant uncertainties involved in this kind of estimations (unit costs, design, etc.) and the scarcity of information in bibliography, it can be concluded that these results are highly acceptable. A major product of this work is the possibility of assessing the cost of the final disposal for any fuel cycle scenario (without specifying the repository design) with a relatively small bias.

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JOINT USE MODULAR PLANT PROGRAM TO SUPPORT RD&D NEEDS FOR INTEGRATED ENERGY SYSTEMS

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Abstract

The premise of Joint Use Modular Plant (JUMP) Program is to enable both commercial use and research, development and demonstration (RD&D) activities within a single multi-module nuclear plant, wherein a specific module would be allocated to RD&D use via a prearranged agreement between the operating utility and the national laboratory conducting the research activities. The JUMP Program would support increased and expanded use of nuclear energy in the U.S. for various energy applications through the use of one nuclear power module within a NuScale plant for RD&D purposes. In addition to facilitating and demonstrating commercial SMR deployment in the U.S., the primary objective of the JUMP RD&D program is to support multiple current and future DOE-NE RD&D programs. If implemented, the JUMP Program would support demonstration of the safe utilization of nuclear energy for reliable, secure power for resilient microgrids; demonstrate application of nuclear energy beyond the electric sector; provide a relevant test environment for advanced technologies and materials; exercise the supply chain for SMR deployment and help establish new supply chain options; and exercise the regulatory structure beyond traditional large scale light water reactors (LWRs) used solely for electricity. The opportunities made possible by conducting this RD&D using an at-scale nuclear module that is equivalent to a commercial unit, and operating within a larger commercial plant, are expected to provide unique benefit to the research programs.

1. INTRODUCTION & MOTIVATION

Nuclear energy is vital to the future economic growth of the U.S. and central to our energy security. Nuclear generation provides clean, abundant and reliable energy — accounting for 56% of the emission free electricity in the U.S. in April 2018 [1] — and has a proven track record of safety and efficiency. While existing and new large nuclear plant designs offer the potential to meet the needs of traditional, large grid electricity consumers, the next generation of smaller and more robust designs is needed to expand nuclear energy to broader markets. These markets include electricity for small or isolated communities, as well as niche customers, such as mission critical facilities. SMRs are also inherently well suited to couple with industrial facilities to provide clean and reliable process heat. The high level of safety and plant robustness that can be designed into SMRs also provides a valuable asset for increasing the resiliency of our national grid and industrial infrastructure.

In order to realize the benefits of SMRs, sustained federal support is essential for the development and demonstration of this critical asset. New reactor designs capable of meeting the requirements of non-traditional customers representing broader energy markets will require considerable innovation, which also requires a substantial financial investment. By working with industry to ensure the timely development, demonstration, and deployment of SMRs, the U.S. government would help create a secure U.S. energy future and recapture our leadership in the global nuclear energy market.

The NuScale water cooled SMR is expected to be the first SMR deployed in the U.S. The Utah Associated Municipal Power Systems (UAMPS) has begun active pursuit of licensing an SMR plant in its service area. UAMPS has identified a preferred site at Idaho National Laboratory (INL) for the initial NuScale plant. UAMPS, INL and the U.S. Department of Energy are currently in discussion regarding potential use of one NuScale Power Module™ (NPM) within the UAMPS plant to support RD&D activities. The NuScale plant concept of small, highly hardened and independent power trains in a shared pool environment offers the potential for diverse utilization of individual modules; a full NuScale nuclear power plant (NPP) would include up to 12 NPMs, nominally 50 megawatts electric (MWe) each.

The JUMP Program would support DOE's research mission. Research programs that are of interest to DOE and are relevant to JUMP include demonstration of novel applications of nuclear energy, the value of nuclear to grid resilience, new technologies applicable to nuclear energy, and resilient microgrids. Providing joint use functionality for the proposed UAMPS/NuScale plant is attractive to INL and DOE as a potentially cost effective means to expand research capabilities of the national laboratory within its mission space (i.e., RD&D of new nuclear technology); specific analysis of alternative options to achieve the established research goals and development of associated cost estimates will be completed in Fall 2018. This paper provides an overview of the JUMP program plan, envisioned RD&D, and the proposed path forward for establishing the program.

2. OVERVIEW OF RESEARCH OPPORTUNITIES

Envisioned JUMP research pathways include focused use of the thermal and electrical energy produced to demonstrate use of nuclear energy in energy storage systems, coupled industrial processes, or secure microgrids, as well as the testing and demonstration of advanced technologies.

2.1. Constraints on RD&D activities

Expeditious deployment of the first U.S. SMRs is essential to achieving economic and national security goals. As such, it is imperative that research opportunities leveraging the first SMR plants do not impose any significant schedule delay or risk to commercial operation. This potential is most apparent with respect to licensing impacts of proposed RD&D activities given that this and all subsequent SMR plants will be commercial facilities licensed and regulated by the U.S. NRC. Therefore, the identification of JUMP RD&D projects must consider potential impacts of the proposed RD&D on regulatory processes, including the associated design certification (DC) and combined license (COL) processes.

UAMPS has expressed flexibility as to how DOE might use the JUMP NPM as long as the RD&D activities do not create undue NRC licensing challenges that would adversely impact the associated licensing timeline. While this requirement may limit some of the initial candidate RD&D activities that are of significant interest to the applied research programs, it ensures that the primary mission of the UAMPS project — deploying new SMR plants in the U.S. — is not hindered. Once licensed and operating, future RD&D within the JUMP module that could require more significant design and license modification may be considered.

Fig. 1 provides a rendition of an individual NPM. Testing and demonstration of advanced technologies within the JUMP NPM, such as installation of a new sensor or component within the outer containment vessel, is expected to be the most challenging RD&D application, as installation of these technologies will likely have an impact on the standard plant design. Integration of energy storage or coupled industrial processes are less likely to have as significant of an impact, as they would be integrated within the balance of plant systems rather than the NPM.

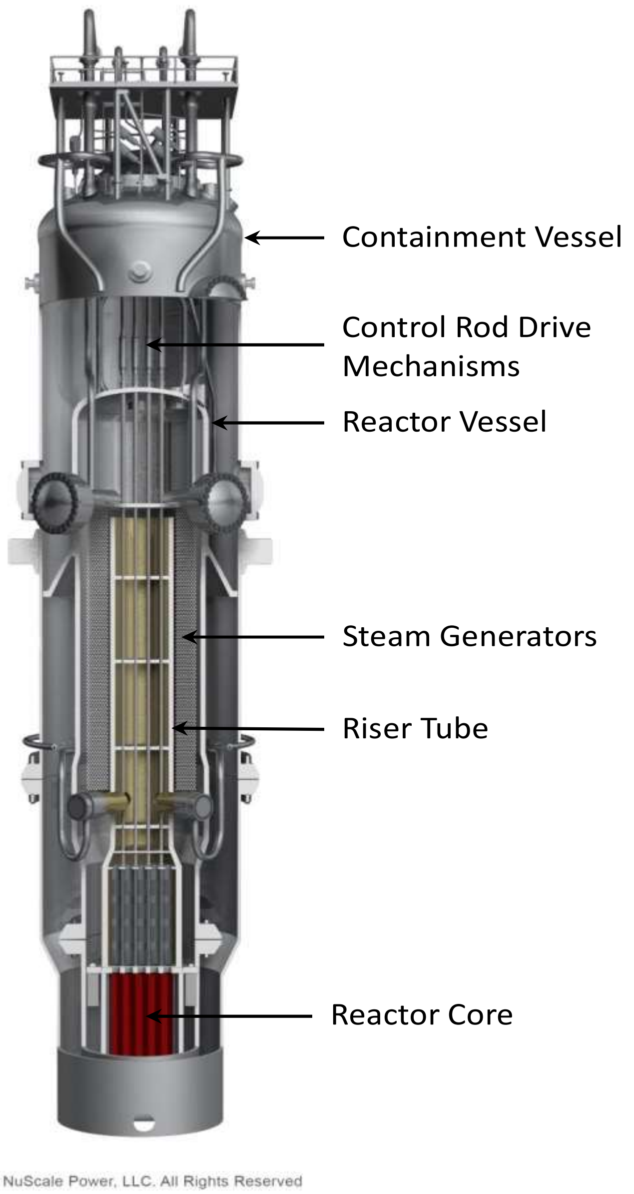

FIG. 1. Rendition of the NuScale Power Module™.

A diagram of the NPM coupled to its dedicated power conversion system is shown in Fig. 2. It should be expected that any alteration of the secondary side systems, such as might be required to access main steam from the NPM, will require the addition of a decoupling heat exchanger to isolate the RD&D components from the NPM secondary coolant system.

JUMP RD&D activities would be planned and conducted in phases to allow for further investigation of the benefits and challenges of proceeding with the program prior to beginning design and fabrication activities for JUMP related hardware. Most RD&D projects are likely to require some license amendment, as they will impact aspects of plant operations and they will utilize the JUMP NPM beyond electricity production alone. Potential licensing impacts, including the specific integration plan for any JUMP specific components, will be identified and evaluated as part of the research planning activities, prior to investment of significant time and funding to the proposed RD&D activity.

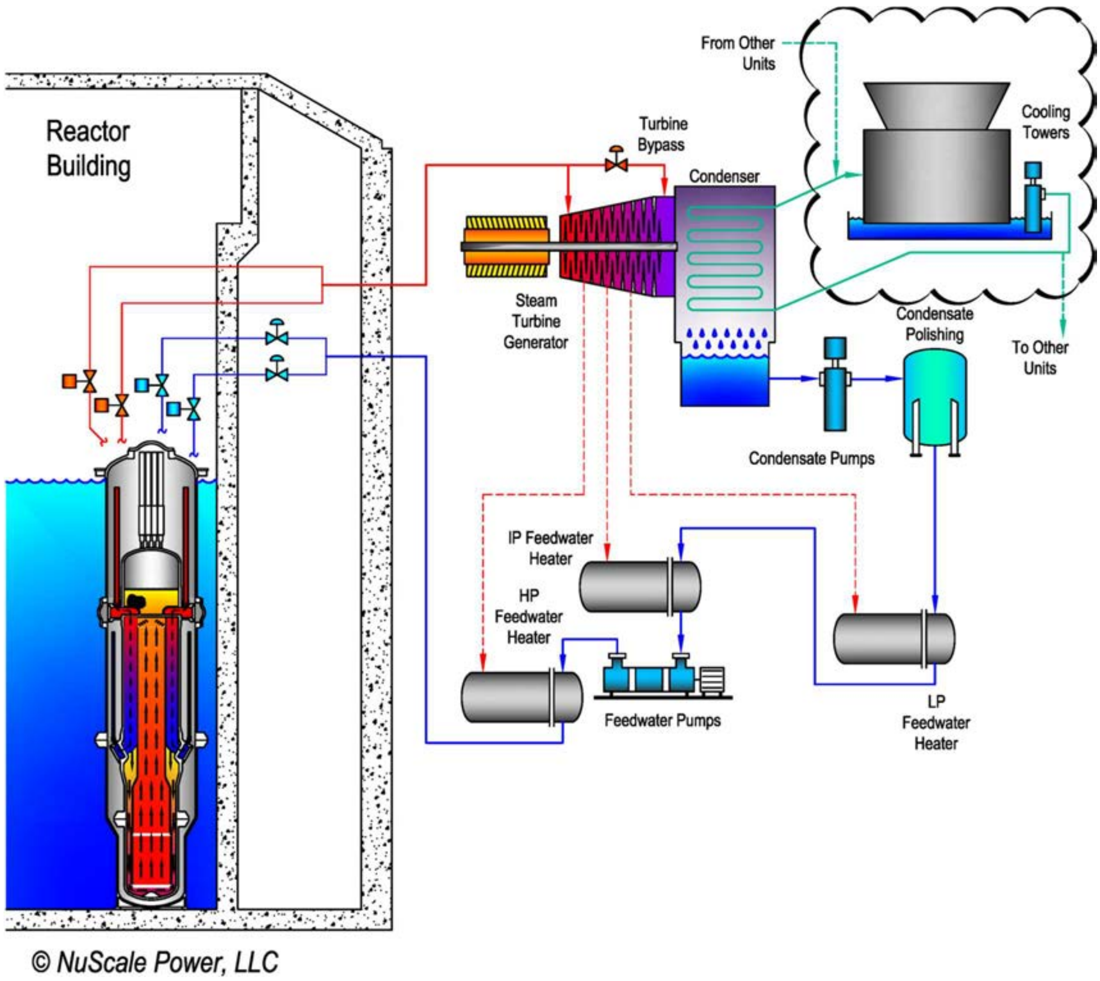

FIG. 2. Diagram of the NPM primary system and the corresponding secondary system, including power conversion equipment.

The JUMP Program will be conducted in phases, roughly categorized as follows:

- Phase 1 (2018–2021): Planning
  - Develop detailed program plan, RD&D plan, schedule and budget; includes analysis of alternatives to JUMP to achieve the identified research objectives;
  - Establish contractual agreement terms between UAMPS and INL for JUMP NPM use;
  - Conduct preliminary JUMP RD&D hardware design activities;
  - Assess licensing impacts and develop inputs to licensing (includes significant engagement of NRC staff).
- Phase 2 (2021–2026): Precursor Activities, Hardware Installation, and Pre-operational RD&D
  - Modelling, benchtop testing, and scaled non-nuclear demonstrations for the selected RD&D activities;
  - Final design of JUMP hardware, including additional facilities or infrastructure required;
  - Continued engagement with NRC; modification of license or license amendments (as required);
  - Procurement and installation of JUMP related hardware and infrastructure.
- Phase 3 (2027–2037): Post-operational JUMP RD&D
  - Initial testing of hardware;
  - Execution of JUMP RD&D plan;
  - Assessment and planning for future use of JUMP.

2.2. Definition of research pathways

Several potential research pathways have been identified for JUMP. Each pathway is briefly described below, with additional clarification and detail to be added as the program matures. The RD&D options will be refined and prioritized in Fall 2018.

2.2.1. Pathway 1: Demonstrate 'beyond the grid' applications of nuclear energy

Research institutions, vendors, and utilities have expressed interest in transforming how we use nuclear energy, optimizing energy use through novel systems integration and process design. Such applications would expand the uses of nuclear energy beyond the electrical grid to produce energy services and products. These 'integrated' or 'hybrid' applications overcome the technical, economic, and institutional barriers that currently inhibit wider use of nuclear energy in both centralized and distributed energy systems. Integrated energy systems are particularly important as rapid buildout of renewable technologies has resulted in high variability in net electricity demand[18] that must then be met by traditional dispatchable generation. Demonstration of beyond the grid applications will be the primary focus of initial JUMP RD&D. A technology development program plan for Nuclear-Renewable Hybrid Energy Systems issued in March 2016 provides background on the motivation for such research, technology options of interest, and plans for modelling and simulation and experimental demonstration of integrated systems [2].

This research element will substantially impact secondary side systems, including potential main steam bypass (partial or full) of the turbine under operating scenarios that reduce electricity production to maximize the production of an alternative commodity. In these cases, a decoupling heat exchanger that minimizes deviations in the feedwater returned to the NPM may be necessary. This provision is needed to reduce potential impacts to the NPM standard design safety basis and to ensure physical isolation of the secondary coolant and working fluids used for the research programs. Potential impacts on the COL will be identified and evaluated. Selection of specific RD&D options will consider colocation risks for the facilities and the flexibility attributes provided; flexibility attributes are further defined in EPRI (2017) [3].

JUMP would provide a platform to demonstrate coordinated use of nuclear generation with nearby renewable installations (e.g., wind and hydro generation near the INL Site) and non-electric use of thermal energy produced by the JUMP module. Energy users range from thermal energy storage systems to industrial processes to produce various commodities, each of which lend additional flexibility to electricity generation from the nuclear plant, enhance energy utilization efficiency, and potentially increase the economic competitiveness of both existing and future nuclear plants. JUMP allows for demonstration of physical coupling options for various thermal energy storage systems, industrial thermal energy customers, and innovative advanced processes. Design and demonstration of thermal energy storage would also include energy recovery options including, but not limited to, electrical power generation. Additionally, operation of the JUMP module would demonstrate effectiveness and reliability of control systems, and the human factors interface necessary to implement system control, for dynamic apportionment of energy across multiple energy users (electrical and non-electrical) in response to various internal and external indicators.

Options for beyond the grid applications that may be demonstrated include water desalination/purification, hydrogen generation for use in fuel cells or numerous industrial processes, ammonia production, metals production, paper products, etc. It is anticipated that demonstration of selected integrated system options within JUMP would be preceded by non-nuclear (electrically heated) testing using a scaled test facility. Such a facility is currently under development within the Systems Integration Laboratory at INL [4]. Research and development of the relevant components, systems and control strategies would be conducted during Phase 2 of the JUMP Program, while at-scale demonstration of the integrated applications would be demonstrated during Phase 3.

[18] Net demand is the remaining load that must be met by conventional dispatchable generation sources after variable generation is subtracted from the total load (electricity demand).

2.2.2. Pathway 2: Develop, test, and demonstrate advanced technologies that could be deployed in nuclear reactors

The JUMP module would provide unique opportunities to test and demonstrate advanced technologies in relevant reactor conditions. Component technologies and operational approaches that are currently envisioned are listed below, but this list may be expanded as the program is further developed:

- Provide real time operating data for modelling and simulation code validation (also see Pathway 4);
- Develop and demonstrate physical and cyber security approaches (including supporting technologies, control system architecture, etc.);
- Develop and demonstrate use of advanced sensors for real time plant monitoring (e.g. non-intrusive instrumentation);
- Test advanced fuels and materials (with associated post-irradiation examination [PIE]);
- Develop, test, and demonstrate advanced fabrication methods for factory based manufacture of the modules;
- Apply artificial intelligence methods for plant monitoring and control to establish aspects of semi/fully autonomous operations;
- Develop and demonstrate innovative approaches to configuration management and operational services;
- Develop and test non-proliferation technologies.

The RD&D areas noted above are part of DOE's current portfolio, distributed across a number of different programs, and would significantly benefit from use of a prototypic (commercial nuclear) environment that is part of a research facility. An evaluation of the needs for these research areas will be conducted to identify the specific capabilities that JUMP can provide to support DOE's broad RD&D mission and their suitability for conduct during Phase 2 and/or Phase 3 of the JUMP Program.

2.2.3. Pathway 3: Enable nuclear supply chain solutions

NuScale is in the process of developing the supply chain necessary to support the construction phase for the UAMPS plant. JUMP would provide an opportunity to further expand the nuclear supply chain for future plant construction by supporting demonstration of components fabricated via advanced manufacturing or other novel processes in addition to using components fabricated using standard techniques in its initial operation. DOE national laboratories are performing RD&D on advanced manufacturing methods and processes that have significant potential to create new approaches for the manufacturing and fabrication of reactor parts and components. Demonstration of performance in the JUMP NPM would support the development and qualification of new processes for nuclear component fabrication that aim to reduce cost and schedule associated with nuclear plant builds. Specifically, JUMP would provide component and system level test beds to support demonstration and qualification of advanced manufactured parts in a prototypic operational environment alongside their standard counterparts. While components could be fabricated using a number of facilities across the DOE complex or within industry or universities, the proximity of the INL characterization facilities (for both pre- and post-irradiation characterization) to the JUMP NPM provides a means to accelerate the development, testing, and qualification of new fabrication processes and components. Overall, the capability could benefit the existing large scale LWR fleet as well as further develop the supply chain for future SMR deployments. It is expected that relevant RD&D activities would occur during both Phase 2 and Phase 3 of the JUMP Program.

2.2.4. Pathway 4: Evaluate and inform new regulatory approaches

JUMP would provide an opportunity to establish and exercise regulatory strategies that would encompass non-traditional applications of nuclear energy, regulatory processes unique to SMRs (e.g. factory based inspections, tests, analyses, and acceptance criteria (ITAAC) [5]), and NPM use for testing and demonstration of advanced technologies. This research pathway includes licensing aspects associated with operation of a plant that contains modules for diverse purposes. Specifically, this refers to the mix of commercially operated modules for electricity production alongside a module that may be used for research activities. The latter module would be configured and operated in a manner that supports demonstration of advanced technologies, including the potential for non-electric use of process heat to support an energy user outside of the nuclear island, as described in Pathway 1, or concurrent production of electricity and a non-electric product. Licensing and demonstration of these applications via JUMP would support use of current fleet LWRs, SMRs, and advanced reactors for the production of potentially higher value commodities relative to electricity on the grid. In addition, JUMP would provide an opportunity for the validation and enhancement of high fidelity advanced modelling and simulation capabilities for LWR technologies by providing reactor operating data to validate models and software.

TABLE 1. KEY RD&D STEPS AND CRITICAL OUTCOMES FOR THE DEFINED RESEARCH PATHWAYS

CRITICAL OUTCOMES	PHASE 1 TASKS (2018–2021)
1. Demonstrate 'beyond the grid' applications of nuclear energy	1.1. Create a prioritized list of non-electric use applications 1.2. Perform analysis of alternatives for priority applications 1.3. Develop cost estimate for the selected applications 1.4. Create an integrated modeling, testing, and licensing plan with reactor developers, utilities, and applicable end users 1.5. Develop a laboratory scale capability and demonstrate integrated system performance (electrically heated) 1.6. Update prioritization of leading non-electric use cases, associated technical needs, and licensing plan based on analysis and lab scale testing
2. Demonstrate advanced technologies	*Various approaches may be applicable depending on the specific technology to be demonstrated. Example provided for advanced instrumentation:* 2.1. Develop an instrumentation plan to support deployment in an SMR, particularly for non-invasive flow measurements 2.2. Establish a licensing basis for non-safety related instrumentation and operations 2.3. Work with vendors on the most desirable measurements to improve performance and safety 2.4. Create prototype instruments for lab scale (non-nuclear) testing 2.5. Select instrumentation for JUMP RD&D and develop associated licensing plan
3. Enable nuclear supply chain development and deployment	3.1. Establish a supply chain development plan with the vendor 3.2. Develop a prioritized procurement and test strategy 3.3. Execute early supply chain demonstration projects, to include advanced manufacturing projects
4. Inform new regulatory approaches	4.1. Work with vendors and utilities to create a licensing strategy 4.2. Develop an NRC engagement strategy 4.3. Engage NRC on proposed regulatory approaches 4.3. Establish safety margin evaluation models

3. PATH FORWARD

A preliminary schedule of key activities associated with JUMP has been defined. Initial activities, planned for completion by the end of calendar year 2018, include refinement of the potential RD&D scope, including clear definition of the technical objectives associated with each research activity; conduct of an analysis of alternative options to achieving these technical objectives; and development of preliminary (order of magnitude) cost estimates for each of the priority RD&D activities prior to investing in detailed design and engineering activities for the specific research components. A more detailed schedule will be developed as the work progresses. Table 1 identifies steps to be taken within the Phase 1 research planning activities for each defined JUMP research pathway. Specific DOE programs conducting research in these areas will be engaged in the refinement of the research plan.

Under the proposed JUMP program, INL would acquire services and/or equipment necessary for the purposes of research and testing from UAMPS. These services are not currently available from a federal source, and the implementation of JUMP is expected to be more cost effective than DOE developing its own SMR program for similar purposes. Note that RD&D components would be developed by INL staff and would define the desired operating conditions for the RD&D activity, but UAMPS would retain the role of plant operator. Specific approaches for INL to acquire such services from UAMPS are currently in discussion.

4. SUMMARY

The proposed JUMP RD&D program poses a unique opportunity to bolster the U.S. nuclear industry by supporting the demonstration of technologies and operating modalities that could be adopted by either current or future fleet nuclear plants. Through collaboration with an operating commercial nuclear plant, JUMP would provide a cost effective means to support execution of research envisioned by a number of the DOE Office of Nuclear Energy research programs in a relevant environment. Federal investment in the JUMP program would not only advance technologies available for nuclear service, but it would also reduce the risk to industrial partners investing in the deployment of the next generation of nuclear plants.

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NUCLEAR-RENEWABLE HYBRID ENERGY SYSTEMS: INDUSTRIAL APPLICATIONS AND THEIR POTENTIAL MARKETS

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Abstract

Severe climate change, stringent environmental regulations, extreme energy security and unstable energy market are the leading challenges of the current century to be overcome in the present energy supply and demand scenario. To cope with this situation, the hunt for a technological mix of nuclear–renewable hybrid energy systems (N–R HESs) with suitable industrial applications and dynamic potential market is essential. N–R HESs are four steps processes where a nuclear reactor that generates heat is coupled with a thermal power cycle for electricity generation, at least one renewable energy source, and an industrial process that uses thermal and/or electrical energy to produce a valuable product with low carbon emissions. In this study several N–R HESs are explored, potential markets for their generated products are identified and the challenges and opportunities associated with their realization are briefly discussed.

1. INTRODUCTION

The global energy sector is continuously evolving due to environmental, economic and energy security concerns. The share of natural gas and variable generation renewables (wind, photovoltaics etc.) is growing in the electricity sector, more efficient technologies are evolving for the transportation sector while the industrial sector is forced to reduce their greenhouse gas emissions through energy storage, efficiency improvements and advanced combined heat and power initiatives [1,2]. Therefore, there is a great thirst to develop innovative technologies for clean and efficient energy generation which motivate investment and utilization strategies. With the technological advancements of low carbon processes, the utilization of fossil fuels with decarbonization approach could be achieved by considering hybrid energy systems as suitable and economical feasible alternatives.

A hybrid energy system is defined as either a set of various energy generation processes to fulfil the requirement of a single energy consumer (electricity) or can be a single energy generation process that serves multiple energy consumers (electricity, heating, cooling, water etc.) [3,4]. The combined generation of heat and electric power is called cogeneration which is also a form of hybrid energy system where the concept of multiple generation sources and single generation source is applied in an optimized design to serve energy consumers [4,5].

To develop an energy efficient hybrid system for reduced emission of greenhouse gases, the coupling of nuclear and renewable energy sources with fossil fuel production facilities, known as nuclear–renewable hybrid energy systems (N–R HESs), are a very suitable choice in the current energy security situation. The N–R HES concept can be divided into four step processes where (i) a nuclear reactor that generates heat is coupled with (ii) a thermal power cycle for electricity generation, (iii) at least one renewable energy source and (iv) an industrial process that uses thermal and/or electrical energy to produce a valuable product with low carbon emissions.

The economical operation of nuclear power plants (NPPs) require a high capacity factor (large number of operation hours annually at maximum capacity) due to high capital investment and low fuel cost [3,4,5]. Unstable grid and other transient operations of NPPs results in lower capacity factors, which are undesirable. To operate NPPs on the highest capacity factor, the concept of N–R HES is highly desirable for efficient and economical energy production. With the introduction of a carbon tax and a sharp decline in power cost of N–R HESs due to technological advancements, the N–R HESs could show a great potential to become an economically viable option in the future [6]. Numerous potential societal benefits could be obtained from N–R HES such as (a) zero pollutant, flexible, dispatchable and low carbon electricity, (b) reduced pollutant emissions in the industrial sector, (c) grid support and (d) moderation of the effect on electricity price [1].

In the following paragraphs, various combinations of N–R HESs are explored, challenges, opportunities and couplings associated with their realization are briefly discussed. Moreover, potential markets for their generated products are also identified.

2. N–R HES INDUSTRIAL APPLICATIONS

To generate dispatchable electricity without greenhouse gas emissions and to provide clean energy for industrial processes, N–R HES is one of the potential opportunities for industrial applications [1]. Considering various factors like economic, geographic, desired form of output, etc., different combinations of renewable energy sources could be coupled to form a N–R HES as illustrated in Table 1 [3, 7].

TABLE 1. VARIOUS INTEGRATION OF N–R HES

ENERGY SOURCES	COUPLING
Nuclear and biomass	Thermal/Chemical
Nuclear and wind	Thermal/Hydrogen
Nuclear, wind and natural gas	Electrical/Thermal/Chemical
Nuclear and solar	Thermal/Electrical

In the following paragraphs few of the N–R HES options are discussed in detail.

2.1. Oil shale system

Oil shale is a mixture of sedimentary rock with high content of solid insoluble organic matter known as kerogen which upon heating decomposes into hydrocarbons used as a fuel [8]. There are abundant reserves of oil shale in the western United States of America, northern Europe, China, Australia, Jordan, and certain other countries. Fig. 1 shows the share of estimated in place resources of selected countries with significant oil shale formations which depict the USA as the major shareholder [8,9,10].

In Estonia and China these resources have been used for fuel and power production for many decades. Oil shale requires mining and energy extensive refining processes to convert it into gasoline, diesel and other useful energy products. The primary energy source for the decomposition of kerogen can be provided by a base load nuclear reactor which will also provide large supplies of flexible dispatchable, very low carbon electricity where this combination of electricity generation and fossil fuel production with reduced carbon dioxide emissions is called a nuclear renewable oil shale system (NROSS).

A typical baseline model of NROSS consists of a small modular pressurized water reactor (SMR) that operates at full power, a petroleum processing plant, a subheating system that heat the oil shale underground and a renewable energy source (solar or wind). It is assumed that the nuclear reactor in the NROSS operates in two modes, that is heat delivery to the shale and electricity delivery to the national grid. The shale oil is heated to 210°C from the subheating system using reactor steam directly, then to 370°C using electricity produced by the nuclear reactor and/or non-dispatchable solar or wind energy sources depending on the operating mode [8]. A simplified energy flow diagram is presented in Fig. 2.

The fossil liquid fuels (oil shale products) produced by NROSS have the lowest carbon footprints compared to any other known process in the world; therefore, it could be the preferred choice to utilize the last fossil fuel resources in the world. Although NROSS will require significant development and technological efforts, it presents a fair option for efficient, reliable and cleaner energy systems [8].

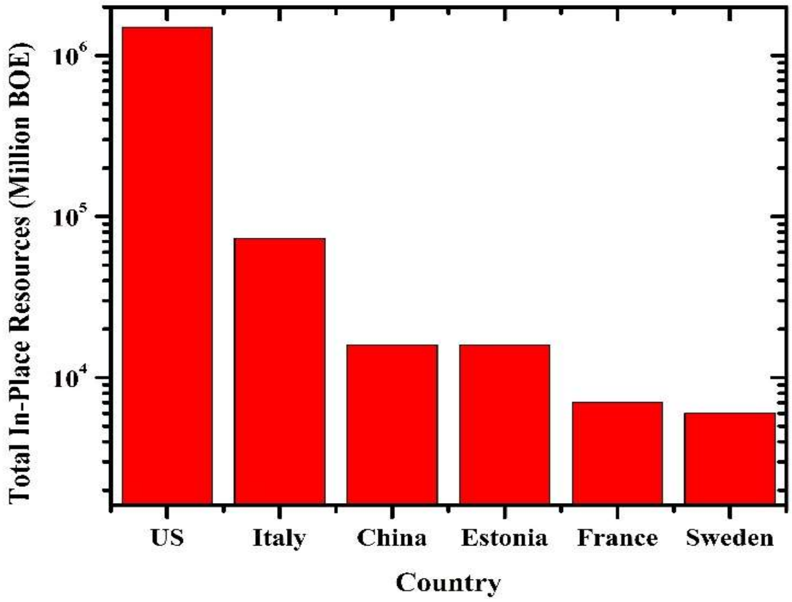

FIG. 1. Oil shale resources for selected countries in barrel of oil equivalent (adopted from Danial Curtis et al. [8]).

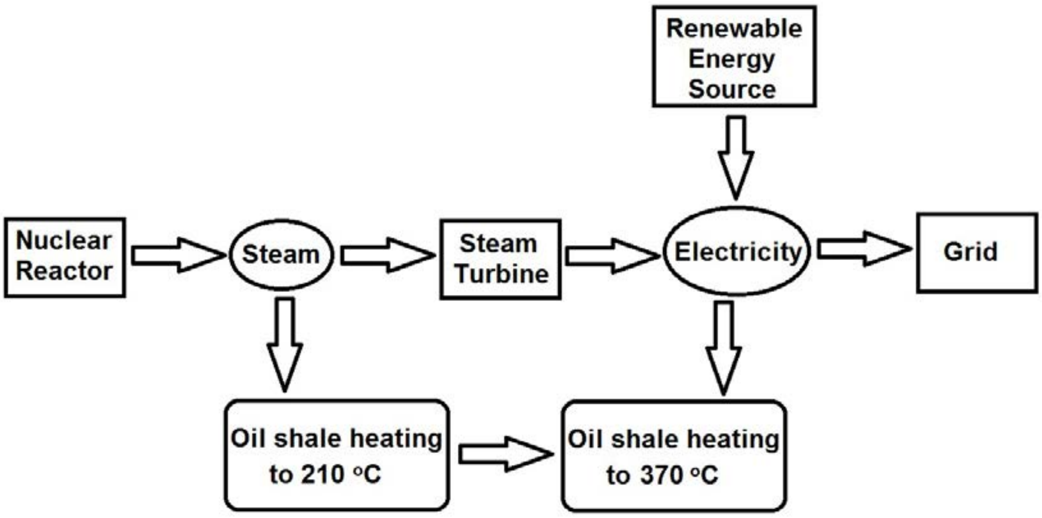

FIG. 2. Flow diagram for a baseline NROSS using PWR option (concept adopted from Danial Curtis et al. [8]).

2.2. Hydrogen production

Hydrogen is an environmentally friendly energy resource which can be stored in large quantities as opposed to electricity. It can be directly converted to electricity without any pollutant emissions and can be used as resource material for many chemical based industries. It can also be used as a fuel for automobile and other energy demanding industrial sectors. Nuclear energy can be used to produce hydrogen, which in turn can be used directly by energy consumers. In a N–R HES option for hydrogen production, it can be produced either by low temperature electrolysis (LTE) where electricity is exclusively used (Fig. 3), or by high temperature electrolysis (HTE) which uses both heat and electricity (Fig. 4) by employing the N–R HES concept [1].

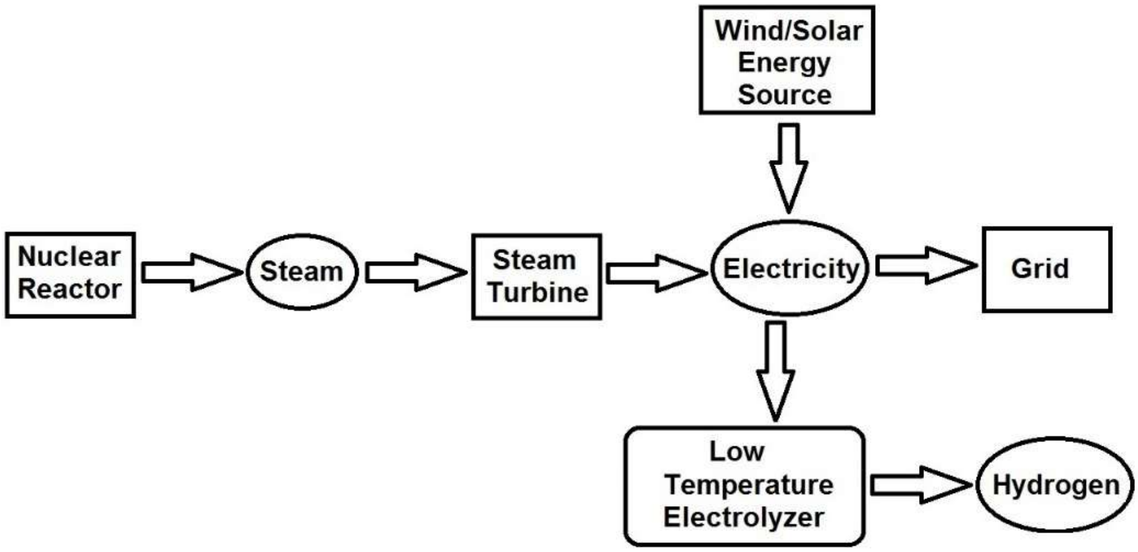

FIG. 3. N–R HES option for low temperature electrolysis (concept adopted from Mark Ruth et al. [1]).

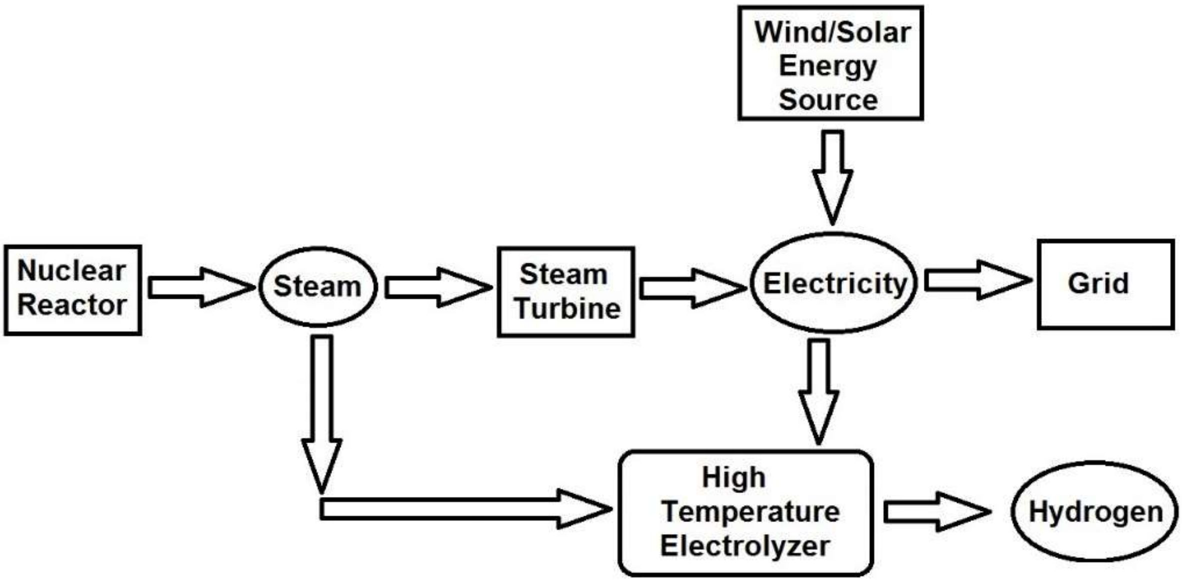

FIG. 4. N–R HES option for high temperature electrolysis (concept adopted from Mark Ruth et al. [1]).

The use of high temperature reactors for hydrogen production presents a viable option since most of these processes have a higher efficiency than low temperature electrolysis.

2.3. Coal based chemical industry

The global coal based chemical industry is growing significantly in coal rich countries of the world such as South Africa, USA, Australia, Indonesia, India, etc., and therefore, there is a lot of potential in the development of low carbon coal based N–R HESs. Fig. 5 shows expected scale of production of major fuel chemicals in 2020 and 2030. It is expected that the hybrid energy replacement rate will grow significantly in 2020 and 2030 by a proportion of 40% and 80% respectively [6,11].

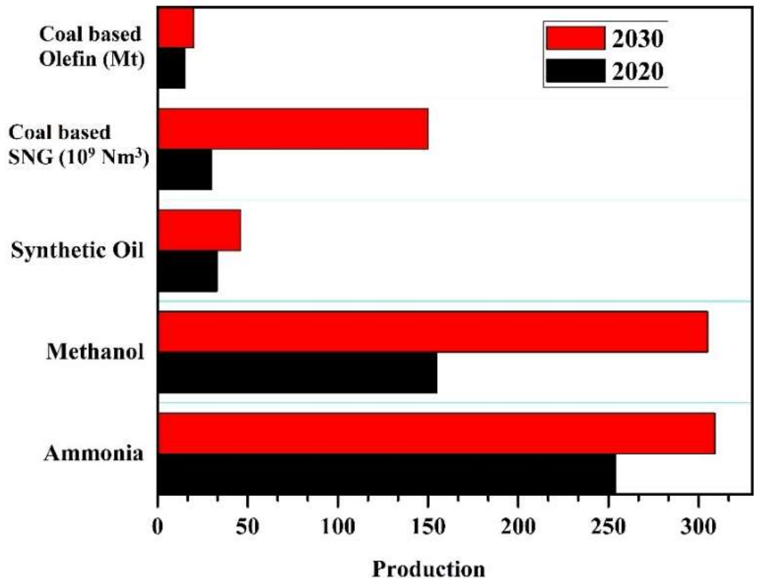

FIG. 5. Expected production of major fuel chemicals in 2020 and 2030 (adopted from Qianqian Chen et al. [6]).

In coal based N–R HESs, the carbon resources are provided by coal while the H_2, O_2, heat and electricity resources are derived from nuclear energy for fuel production and chemical synthesis. This type of combination could not only improve both energy and carbon efficiencies but could also yield a fair balance between carbon and hydrogen and will result in reduced CO_2 emissions [12].

In a typical coal based N–R HES option, H_2 from a HTE plant (which is powered by nuclear reactor) is mixed with syngas generated from coal to obtain the desired H_2/CO ratio while the O_2 from HTE is used for the coal gasification process. The HTE plant replaces the conventional water–gas shift reaction unit and air separation unit [12]. The chemical resources required for other processes are the same as in conventional systems such as coal gasification, syngas cleaning, sulphur recovery, coal milling, etc. Electrical resources could be provided by the nuclear reactor and/or renewable energy sources (wind, solar etc.). Steam could also be provided by the nuclear reactor for coal drying and other associated processes. A simplified flow diagram is shown in Fig. 6.

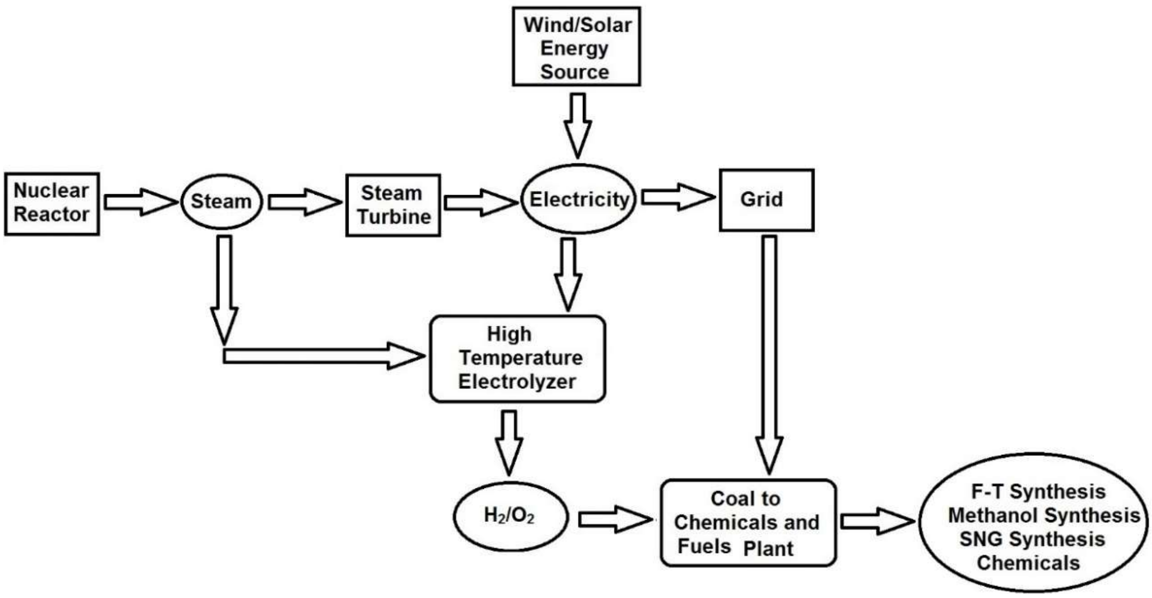

FIG. 6. Simplified energy flow diagram of N–R HES option for coal based chemical industry (concept adopted from Qianqian Chen et al. [6]).

2.4. Sea water desalination and sea water reverse osmosis

Fresh water is one of the major concerns globally for sustainable development while future demand is growing exponentially due to rapid growth of population, scarcity of fresh water resources, industrialization and increasing urbanization. Most of the desalted water is produced from sea water either by sea water desalination or by sea water reverse osmosis. Both of these technologies are energy intensive and require heat and electric power. Nuclear desalination is considered as one of the most viable, cost effective and long term solutions to produce fresh water from sea water. A N–R HES for sea water desalination could be an excellent alternative as many nuclear power plants are located on the seashore and use sea water for their cooling loop. In the N–R HES option for sea water desalination, both steam and electricity are used to produce fresh water as shown in Fig. 7.

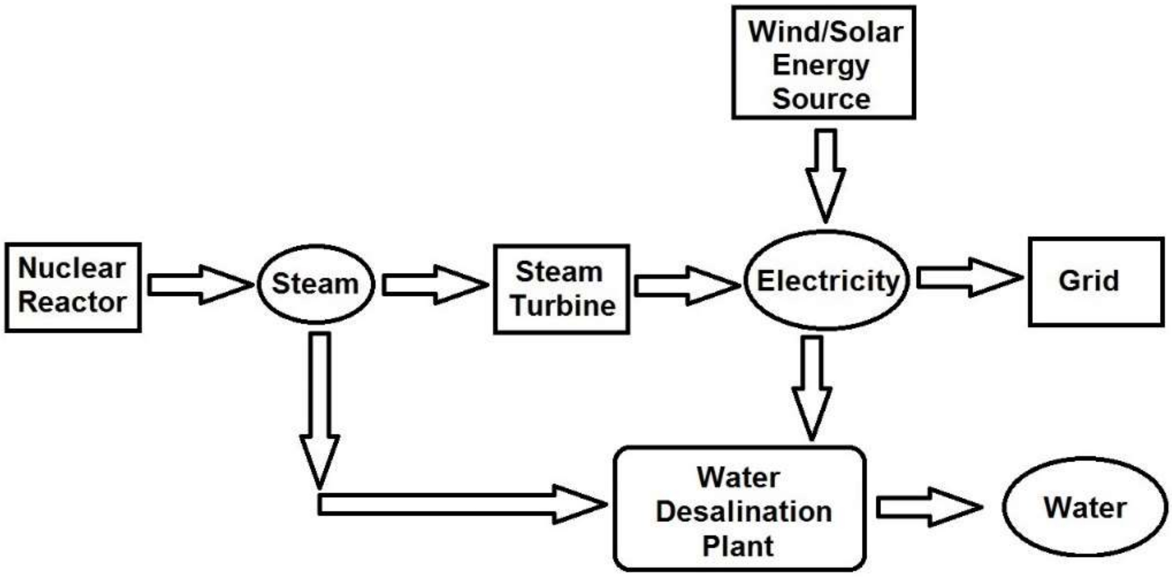

FIG. 7. N–R HES option for sea water desalination.

The N–R HES option for sea water reverse osmosis could also be an alternative to produce fresh water from sea water where electric power produced by the nuclear reactor could be used to produce fresh water as illustrated in the simplified energy flow diagram in Fig. 8.

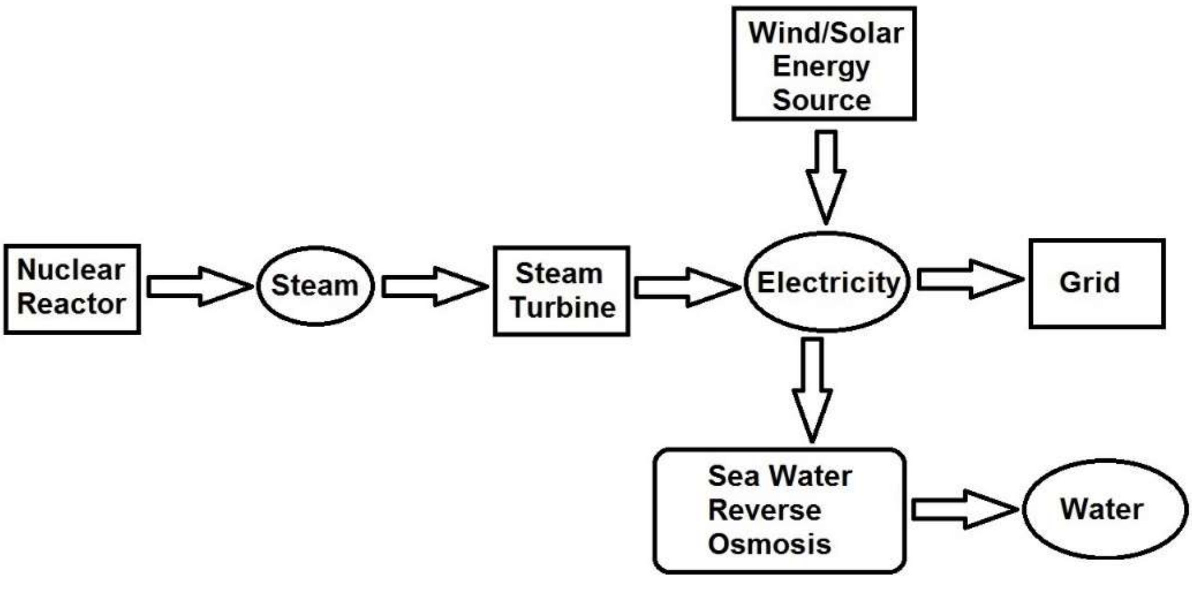

FIG. 8. N–R HES option for sea water reverse osmosis (SWRO).

3. N–R HES POTENTIAL MARKET

The major advantage of N–R HESs over conventional fossil energy systems is their reduced pollution emissions. The needs of many industrial applications could be fulfilled using small modular reactors (SMRs). Temperature amplification techniques could be used on light water reactors (LWRs) to accomplish industrial steam and heat requirements. The coupling of high temperature reactors (molten salt cooled design, etc.) in N–R HESs would expect to decrease the requirement to augment the steam heating process, but these technologies will require longer development time, high cost and uncertainties [13].

The potential nuclear reactor energy delivery source (steam) from N–R HESs for industrial applications can be divided into three types, i.e. low pressure steam (LPS), intermediate pressure steam (IPS) and high pressure steam (HPS) [13]. The range for LPS is less than 1 MPa, IPS is from 1 to 10 MPa, and HPS is greater than 10 MPa. The following are some of the industrial processes which could represent a potential market for N–R HESs [13]:

- The processes of district heating, evaporation and drying processes are operating at 30–200°C and would require hot water and LPS.
- Pulp paper and food processing applications are operating at 30–300°C and would require IPS.
- Distillation and thermal cracking processes of oil refineries and pharmaceutical are operating at 300–6500°C and would require HPS and hydrogen.
- Hydrogen production from water splitting (low temperature electrolysis, high temperature electrolysis, thermal loops) is done at 100–900°C and would require IPS to HPS, hot gas and molten salt.
- Inorganic mineral production (soda ash, fertilizers, phosphate, sodium hydroxide, chlorine, etc.) are done at 350–500°C and would require HPS, hot gas and molten salt.
- Distillation, torrefaction, pyrolysis and gasification processes in the biofuel refineries are done at 150–1000°C and would need LPS, IPS, HPS, hot gas, molten salt, H_2 enriched flames and hydrogen for fuel upgrading.
- Chemicals manufacturing (methanol, 1,4 butanediol ethylene/propylene, acetic acid, formaldehyde, resins, hexamethylene diamine etc.) processes are operating at 150–600°C and would require LPS, IPS, HPS, hot gas, molten salt, H_2 enriched flames and hydrogen for chemical synthesis and electrochemical processes.
- Hydrogen production from hydrocarbon is done at 750–900°C and would require hot gas and molten salt.
- Coal gasification for syngas and chemical synthesis is done at >1000–1300°C and would require O_2 for oxy-fired gasifier and H_2 for fuel synthesis.
- Production of glass, iron, steel and aluminium etc. are done at >1000–1500°C and would require induction heating, electric arc, plasma, electrochemical processes, H2 enriched flames, and H_2 as reductant.
- Production of cement is done at >1300–1800°C and would require, H_2 enriched flames, and H_2 as reductant [13].

4. N–R HES COUPLINGS

This section describes the process of coupling nuclear and renewable energy sources in a hybrid system to produce required energy products. The elements of nuclear–renewable hybrid energy systems have many aspects of couplings between each other which include thermal, electrical, chemical, hydrogen, etc. A review of the most important types of coupling indicated by researchers [3,7,14–24] are discussed in the following paragraphs.

4.1. Thermal coupling

An important objective for N–R HESs is the effective alternate uses of generated heat when power production is not required due to low demand conditions or the unavailability of the grid. New revenue streams can be created by developing technologies that enable heat utilization in an industrial process despite reducing reactor output or releasing energy by cooling. This shared use of nuclear thermal energy is not new and is currently used in Europe for combined power generation and district heating [3,14,15]. Industrial processes that require greater thermal inputs could also be coupled in a nuclear renewable hybrid system [3]. For instance, steam in a power cycle could be rerouted to energy storage and some other industrial users before its condensation in the turbines and condensers. Chemical production processes that require from low to high temperature process steam and hot water could also be coupled with N–R HESs.

4.2. Electrical coupling

Electrical coupling is very important for the design and operation of hybrid energy systems; therefore, their dynamic market value and uses for electricity must be considered for the integration of nuclear and renewables in N–R HESs. The electricity from the nuclear power plants can be used internally or can be diverted to the energy market which depends on the energy market status where the facility operator can play a deciding role. When the electricity demand is higher, its prices can be increased and energy can be diverted from the industrial processes [3]. When the electricity demand is low, its prices could be decreased along with the production of surplus electricity by a hybrid energy system. To increase revenue, it is more economical in this scenario to divert electricity to the industrial processes. This surplus electricity in the hybrid systems could be stored in energy storage devices like batteries, compressed air technology, hydropower pumping, etc., and could be dispensed to users when the energy market is favourable.

4.3. Chemical and hydrogen coupling

Nuclear power reactors can be designed to provide process heat for the chemical industry to produce various chemicals like ammonia, fertilizers, hydrogen, petrochemicals, syngas, and many other chemical products that can be used as feedstock in industrial applications [3]. Nuclear reactors can provide the process heat and steam necessary to carry out these reactions. High temperature gas cooled nuclear reactors can produce superheated helium that can be used in steam reforming to replace fossil fuel burners [16]. The production of diesel by the Fischer–Tropsch process could be coupled with nuclear process heat in a N–R HES [17,18]. Many unit operations in the refining and upgradation sections of chemical plants could use process steam and hot water from a nuclear power reactor [19]. Hydrogen is an essential feedstock in the chemical industry and could be obtained from water splitting in N–R HESs as discussed earlier.

Many researchers classified hydrogen as a special case of chemical coupling in N–R HESs [3,7,13]. A significant amount of research has been done for the development of hydrogen production techniques, as hydrogen is an important raw material in the chemical industry and could be used as fuel. Nuclear power and heat based hydrogen production technology has been studied significantly by many investigators apart from its normal production from natural gas by steam methane reforming [20,21,22]. Hydrogen can be manufactured in N–R HES through two main routes, which are thermochemical processes and electrolytic processes. In thermochemical processes, hydrogen is produced by a series of chemical reactions at 750ºC and 1000ºC where oxygen is extracted from water [23,24]. The heat can be provided by employing high temperature nuclear reactors, CSP technology or the combination of a lower temperature nuclear reactor with CSP. In electrolytic processes, electrical power is used to split water into hydrogen and oxygen. High temperature electrolysis increases the electrical efficiency of hydrogen production by running at temperatures ranging from 100ºC to 850ºC, consuming heat along with electricity.

5. N–R HES OPPORTUNITIES AND CHALLENGES

5.1. Opportunities

Integrating nuclear and renewable energy into a single hybrid energy system coupled through informatics linkages would enable the nuclear plant to run at high capacity while addressing the need for flexibility of generation rates and producing energy services and low carbon coproducts. A future hybrid nuclear renewable energy facility incorporating an appropriate industrial process presents opportunities to generate revenues from a variety of product streams and avoid capital inefficiencies of underutilized capacity. The hybrid energy system produces several products which include electricity, hydrogen, natural gas and hot process gases or steam as well as transportation fuels. Many non-energy outputs, whose production is energy intensive, can be obtained using this hybrid energy system. These include chemical feedstocks for fertilizer, polymers, plastics, and textiles; potable water from desalination of seawater and brines; minerals from geothermal brines; and CO_2 for enhanced oil recovery or as a heat transport medium [3].

5.2. Challenges

Research and development regarding different couplings in nuclear renewable hybrid systems is required before implementation to respond rapidly, efficiently and safely to market signals. The research could start with optimization of the hybrid configuration using both static process models and dynamic system predictive models to understand system response to variable and uncertain grid demand and on-site variable energy production. The development of advanced interconnected sensing and informatics systems that identify all needs and provide information to the control system thus enabling control systems to optimize profitably is also essential [3]. Regarding chemical couplings, new design schemes that are resilient to time varying electrical and thermal inputs are needed because chemical manufacturing plants are generally designed to operate at nearly constant operation. Because hydrogen has its own set of safety codes and standards beside nuclear power plant safety regulations, and it is a highly flammable and explosive substance, it must be manufactured away from a nuclear reactor.

6. CONCLUSIONS

N–R HESs are integrated options for energy production and cogeneration with reduced emissions of greenhouse gases, optimal use of capital and grid flexibility. In this study various options of N–R HES are discussed briefly, their industrial applications are explored, potential target markets for their products are identified, challenges and opportunities associated with them are acknowledged and their couplings are described. The following conclusions may be drawn based on the present study:

- N–R HESs may provide optimal alternative to produce green fuels, chemical and other energy resources.
- Technical development, system analysis and optimization concepts are very important for the realization of N–R HESs and to overcome the challenges associated with these options.
- The concept of a N–R HES and its various production routes could be very attractive to technology developer and policy makers by considering its long term prospective and future sustainable decarbonized energy.
- The N–R HESs could be very attractive by producing electricity when electricity price/demand is high and producing other products when electricity price/demand is low.

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ADDITIONAL CONTRIBUTIONS

The following additional contributions were made at the Technical Meeting:

SYNERGIES BETWEEN NUCLEAR AND RENEWABLES, THE FRENCH PERSPECTIVE

M. BERTHELEMY
CEA Saclay
Gif sur Yvette, France

NUCLEAR AND RENEWABLES IN LOW-CARBON ELECTRICITY SYSTEMS: A SYNTHESIS OF OECD/NEA STUDIES

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GIF ACTIVITIES ON NUCLEAR-RENEWABLE HYBRID ENERGY SYSTEMS

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A EUROPEAN PERSPECTIVE ON NUCLEAR-RENEWABLE HYBRID ENERGY SYSTEMS FOR DECARBONISATION, LOAD BALANCING AND PROCESS HEAT APPLICATIONS

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ISBN 978–92–0–161419–3
ISSN 1011–4289