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Optimal Transition Pathway of Power Systems for Guangdong-Hongkong-Macau Region in China#

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ABSTRACT

Power system decarbonization is no longer debatable for achieving carbon neutrality in China. Guangdong-Hongkong-Macau (GHM) region faces significant challenges towards carbon neutrality due to its fossil-dominated energy structure. Here, we develop a new assessment model for determining optimal transition pathways for GHM power system under various decarbonization scenarios. We found that total system costs for CDR70, CDR85, and CDR100 scenarios are 619, 628, 653 billion USD. Moreover, offshore-wind, nuclear, and electricity import are of great importance for GHM low-carbon transition. Our proposed method is applicable to both regional and national energy system decarbonization.

Keywords: Guangdong-Hongkong-Macau region, power system, low-carbon transition, least-cost optimization

1. INTRODUCTION

Guangdong-Hongkong-Macau (GHM) region is the one of the most economically prosperous regions in China. Its GDP ranks the first in the past 20 years among all Chinese provinces. Because of its vibrant economy and growing population, its energy consumption, especially electricity demand will surely surge in future decades. Currently, fossil fuels mainly coal provides more than 65% of GHM electricity generation. In order to achieve carbon neutrality by 2060, it is necessary for GHM region to transit from a fossil-intensive power system to a carbon neutral one.

Many works have studied electricity system transitions in national or regional scales. Zeyringer et al. [1] designed low-carbon transition pathways for Great Britain's power system, aiming to achieve a renewable penetration of 50% and 80% in 2050. They accounted for inter-annual variability of weather and showed that weather variability had a significant impact on power supply stability. Bennett et al. [2] extended energy system modeling to include extreme climate events and applied multi-stage stochastic programming to design robust low-carbon power systems. To further unearth the impacts of scales on decarbonization, Trondle et al. [3] studied trade-offs of geographic scale, cost, and infrastructure requirements for European power system decarbonization. They found that scale and spatial distribution of generation and transmission facilities were a key trade-off for deep decarbonization. Cole et al. [4] combined expansion planning and operation simulation to quantify the challenges of achieving a fully renewable power system for US, while Daggash and Mac Dowell [5] analyzed the least-cost transition pathways for structural evaluation of UK power system to meet mitigation burden.

National-scale power system planning normally gives an overview of an energy paradigm with state or provincial resolutions. It is necessary to provides more details on energy transition with finer spatial resolution. Zhao and You [6] proposed a bottom-up optimization framework for low-carbon transition of New York's power system. Luo et al. [7] analyzed transition pathways o energy systems towards deep decarbonization for Sichuan province, China. Kobashi et al. [8] explored the potential of combining photovoltaics and electric vehicles for deep decarbonization of Kyoto's power systems. These contributions provide valuable insights on regional decarbonization; however, they do not fully quantify spatial-temporal variability of generation resources and demand for power systems. Moreover, transmission network planning is not properly accounted for so that its potential on deep decarbonization may be underestimated. In this work, we develop an integrated investment planning and operation optimization model to determine optimal transition pathways for GHM power system under various decarbonization scenarios. We consider spatial-temporal variability of generation resources and demand to optimize generation and transmission capacity planning and their hourly operation so as to obtain cost-effective transition pathways.

2. METHODOLOGY

2.1 Energy system optimization model

An energy system optimization model (ESOM) that integrates generation and transmission capacity planning and operation optimization is developed to obtain least-cost decarbonization pathways for GHM power system. Our ESOM has the following key features:

- ✧ The planning period is from 2021 to 2050 with 2021 as initial year;
- ✧ GHM region comprises 22 municipal cities, each of which is model as a node for power demand aggregation;
- ✧ A geographical information system analysis is performed to determine capacity potential and hourly capacity factor for renewable energies;
- ✧ Existing generation capacities are considered for each city, and existing transmission networks are included with transmission capacity and distance between cities.

We consider a set of potential generation and storage technologies for low-carbon transition of GHM power system. Generation technologies comprise clean energy technologies and fossil-based technologies. Clean energy technologies consist of solar photovoltaics (PV), onshore wind turbines, offshore wind turbines, biomass, hydro, and nuclear, while fossil-based generation technologies are composed of combined cycle gas turbine (CCGT), combined cycle gas turbine with carbon capture and storage (CCGT-CCS), coal-fired generation (Coal), and coal-fired generation with carbon capture and storage (Coal-CCS). Moreover, pumped storage hydropower (PSH) and lithium-ion battery (LiB) are included as energy storage technologies for system planning.

2.2 Model scenarios

Here, a business-as-usual (BAU) scenario is set up as base scenario, where fossil resources and carbon emissions are not constrained. Moreover, three decarbonization scenarios (CDR70, CDR85, CDR100) are designed for pathway exploration, as shown in Fig. 1, corresponding to emission reduction trends of China's power system under mitigation goals of China's national determination contrition, global warming of 2℃, and carbon neutrality in 2050.

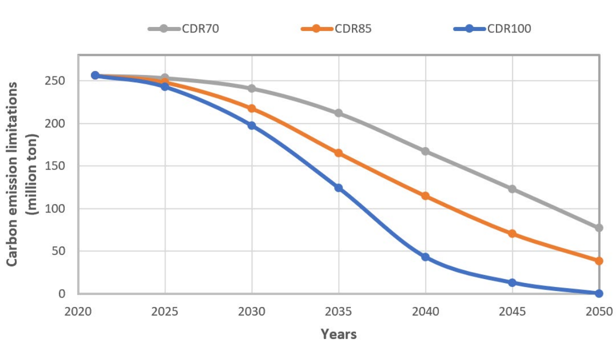

Fig. 1 The annual carbon emission trajectories of different decarbonization scenarios for GHM power system.

3. RESULTS AND DISCUSSION

The cost breakdown of total system costs (TSC) under various decarbonization scenarios as well as decarbonization and electricity costs are shown in Fig. 2. The total system costs (TSC) vary from 578 billion USD in BAU to 619, 628, 653 billion USD in CDR70, CDR85, and CDR100, respectively. Fossil fuel costs (FCS) and operation and maintenance costs (O&M) dominate TSC for BAU scenarios. The two costs decrease continuously when moving from CDR70 to CDR100. Nuclear capital expenditure (CapEx) accounts for only a small fraction (< 8%) of TSC under four scenarios; however, its O&M costs range from 10.5% in BAU to 15.0% in CDR100. Moreover, there is nearly no off-shore wind investments in BAU scenario; however, its CapEx and O&M costs account for 12.5% and 8.3% in CDR100, respectively, indicating that off-shore wind is of great importance on GHM region decarbonization. Transmission CapEx is relatively low (<1.0%) under four scenarios; however, Transmission O&M costs range between 3.3% to 4.2%. Storage CapEx and O&M costs are lower than 3% in four scenarios. It is worth noting that new energy storage installation is unnecessary for BAU, CDR70, and CDR85 scenarios. Electricity imports account for about 4.0% in four scenarios. The average decarbonization costs (ADC) range between 4.8 USD/ton and 7.1 USD/ton, while the average electricity costs (AEC) vary from 17.3 USD/MWh to 19.4 USD/MWh.

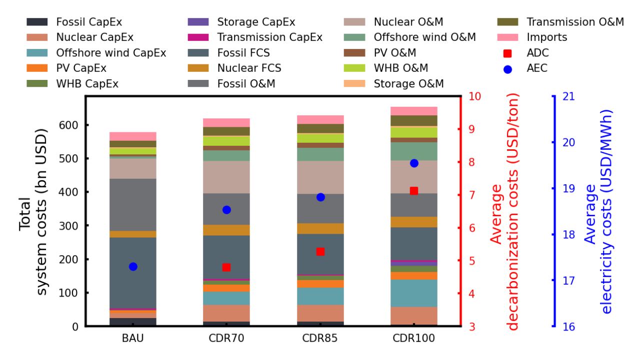

Fig. 2 Cost breakdown of total system costs and average decarbonization and electricity costs under different decarbonization scenarios.

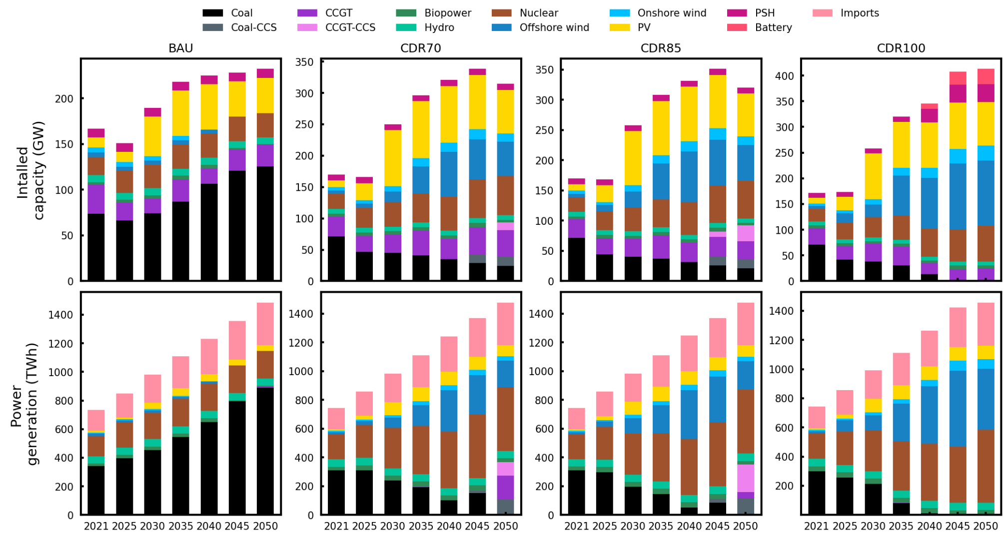

Fig. 3 Optimal capacity mix and power generation for GHM power system from 2021 to 2005 under different decarbonization scenarios.

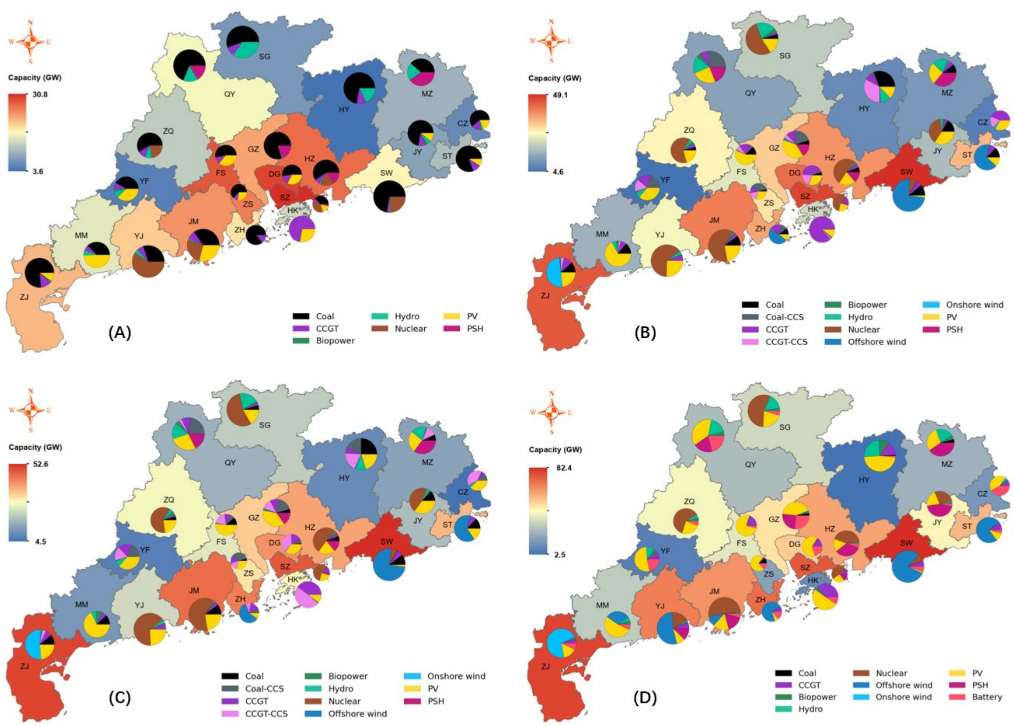

Fig. 4 Geographic distribution of generation capacity for GHM power system in 2050: (A) BAU, (B) CDR70, (C) CDR85, and (D) CDR100.The color on the map shows the total installed generation capacity in a city, while the arc section in the pie represents the installed capacity of an energy technology.

The optimal generation capacity mix and power generation for GHM power system under BAU, CDR70, CDR85, and CDR100 from 2021 to 2050 are shown in Fig. 3. Obviously, fossil-based generation, especially coal-fired generation dominates generation capacity and power generation in BAU. The installed fossil-based generation capacity (coal and CCGT) reaches 149.0 GW in 2050, accounting for 64.2% of total installed capacity (232.0 GW). Fossil based power generation varies from 105.4 TWh in 2021 to in 2050. However, when moving to CDR70, CDR85, and CDR100, coal-fired generation capacity decreases significantly. Its installed capacity reduces from 24.5 GW in CDR70 to 1.3 GW in CDR100 in 2050. Moreover, Coal-CCS and CCGT-CCS are deployed in CDR70 and CDR85, whereas they are not adopted in CDR100 due to deep decarbonization. PV, offshore-wind, and nuclear capacities increase significantly in 2050 and reach 70.0 GW, 55.0 GW, and 61.8 GW in CDR70, 71.0

GW, 59.5 GW, and 61.8 GW in CDR85, and 83.9 GW, 127.1 GW, and 69.3 GW in CDR100, respectively. Despite PV's large installed capacity, its power generation is relatively low due to strong intermittency of solar irradiance. On the contrary, offshore-wind and nuclear generation in 2050 reaches 185.1 TWh and 444.0 TWh in CDR70, 199.7 TWh and 444.0 TWh in CDR85, and 417.7 TWh and 498.0 TWh in CDR100, respectively. Moreover, the imported electricity in 2050 reaches 295.0 TWh, making transmission grid expansion necessary. New energy storage technology installation is only needed in CDR100, where 25.14 GW and 30 GW of PSH and LiB are deployed in 2050. In other scenarios, existing PSH is sufficient to balance renewable intermittency. We can conclude from Fig. 3 that offshore-wind, nuclear, and electricity import are of great importance for GHM low-carbon transition.

The geographic distribution of generation resources for GHM power system in 2050 is shown in Fig. 4. In BAU, nearly every city retains coal-fired generation, and Guangzhou, Shenzhen, Foshan, Dongguan, and Huizhou hold the most intensive capacities. However, in CDR70, CDR85, and CDR100, Shanwei and Zhanjiang are the two cyclites with highest installation capacity. Offshore-wind in Shanwei reaches 36.3 GW in CDR70, 39.3 GW in CDR85, and 65.6 GW in CDR100, while onshore-wind in Zhanjiang reaches 12.8 GW in CDR70, 14.2 GW in CDR85, and 29.8 GW in CDR100. Nuclear generation is essential for GHM low-carbon transition. New installation of nuclear generation is mainly located in Shaoguan, Shaiwei, Zhaoqing and Jieyang, whose installation capacities in2050 are 6.02 GW, 1.02 GW, 7.16 GW, and 3.8 GW in CDR100. Other generation resources are distributed over cities in GHM region to balance the spatial-temporal variability of both renewables and power demand.

4. CONCLUSIONS

In this work, we developed an integrated investment planning and operation optimization model for GHM region to determine the optimal low-carbon transition pathways under various decarbonization scenarios. The model considers detailed existing generation resource distribution and transmission networks, renewable capacity potential and hourly capacity factor, as well as spatial-temporal variability of both renewables and power demand, and thus can identify cost-effective decarbonization pathways for GHM region. We found that total system costs vary from 578 billion USD in BAU to 619, 628, 653 billion USD in CDR70, CDR85, and CDR100, respectively. The average decarbonization costs range between 4.8 USD/ton and 7.1 USD/ton, while the average electricity costs vary from 17.3 USD/MWh to 19.4 USD/MWh. Moreover, we observed that offshore-wind, nuclear, and electricity import are of great importance for GHM low-carbon transition, while storage technology is needed for deep decarbonization.

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