Supporting Information

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Supplementary Figures and Tables

Table S1. National CO2 Emissions from the Power System (billion tons CO2)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| PERIOD | BAU | LC | C70 | C70-LO |
| 2014 | 4.38 | 4.38 | 4.38 | 4.38 |
| 2020 | 4.48 | 4.48 | 3.59 | 3.59 |
| 2025 | 4.89 | 4.89 | 3.09 | 3.09 |
| 2030 | 5.09 | 4.98 | 1.31 | 1.31 |

Table S2. Average Energy Costs of the Power System ($/MWh)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| PERIOD | BAU | LC | C70 | C70-LO |
| 2020 | 54.34 | 54.34 | 57.17 | 57.51 |
| 2025 | 54.76 | 54.76 | 60.33 | 61.08 |
| 2030 | 55.79 | 55.58 | 72.78 | 76.92 |

Table S3. Sensitivity Analysis Scenarios. “C+10%” assumes that the capital costs of offshore wind and storage are 10% higher than those under the corresponding original scenario. “C-10%” assumes that the capital costs of offshore wind and storage are 10% lower than those under the corresponding original scenario. “D+10%” assumes that demand is 10% higher than that under the BAU scenario. “LF25” assumes that the lifetime of solar PV, onshore wind, and offshore wind is 25 years. Otherwise, the lifetimes of those power plants is 20 years. “DR4” assumes that the discount rate is 4%. Otherwise, the discount rate is 7%.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Scenario | Cost | Demand | Carbon cap | Lifetime | Discount rate |
| C70-C+10% | +10% | - | - | 20 | 7 |
| C70-D+10% | - | +10% | - | 20 |
| C50 | - | - | -47% | 20 |
| C70-C-10% | -10% | - | - | 20 |
| C70-LF25 | - | - | - | 25 |
| C70-DR4 | - | - | - | 20 | 4 |

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Figure S1. Power Generation Additions in relation to the BAU scenario by Region in 2020 - 2030. (The eastern region includes Guangdong, Fujian, Zhejiang, Shanghai, Jiangsu, Shandong, Hebei, Tianjin, Liaoning, Guangxi, and Hainan. The inland provinces are other provinces that do not include east provinces).

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Figure S2. Generation Capacity Additions in relation to the BAU scenario by Region in 2020 - 2030.

1. The SWITCH-China model

1.1. Objective Function

The objective function of the SWITCH-China model minimizes the net present value of all investment and operation costs, including:

* capital costs of new power plants;
* fixed annual operation and maintenance (O&M) costs of all power plants;
* variable costs of all power plants, including variable O&M costs, fuel costs for all fossil fuel power plants, start-up/down costs, spinning costs, carbon costs of greenhouse gas emissions;
* connecting costs for integrating power plants into grid;
* capital costs of new transmission lines and distribution infrastructure;
* fixed annual O&M costs of new and existing transmission lines and distribution infrastructure;
* sunk costs, including capital costs of existing power plants, existing transmission lines and distribution infrastructure.

Table S1.1. The Optimization Objective Function

|  |  |  |  |
| --- | --- | --- | --- |
| Generation and Storage | Capital |  | The capital cost of installing generator *g* in investment period *p* is calculated by generator size (MW) and capital cost (overnight cost) ($2016 / MW) of each generation technology in investment period *p.* |
| Fixed O&M |  | (MW) are existing generators in period *p*; (($2016 / MW⋅year) is annually fixed O&M cost for each type of generator *g* in period *p*. (MW) is output power of generator *g* in time point *t.* |
| Variable |  | ($2016/MWh) is variable cost of generator *g* at time point *t*, respectively. ($2016/MWh) is cost of fuel in load zone *z* during period *p*. are time weights that represent number of hours in each study hour. |
| Startup and spinning reserve |  | The cost includes startup cost and startup fuel cost. |
| Connecting Cost |  | is connecting cost for plant *g* in period *p*. |
| Transmission System | Capital |  | are transmission corridors connecting load zone *A* and load zone *B*. (MW) are transfer capability added in transmission corridor in period *p*. (km) is length of transmission corridor . are capital costs of expanding transfer capability in period *p* ($2016/MW⋅km). |
| Fixed O&M |  | are existing transfer capability in corridor in period *p*. are O&M costs of in corridor in period *p*. |
| Local T&D | Fixed O&M |  | are local transmission and distribution capacity in load zone z at period p. are annual fixed O&M costs per MW for existing and new local T&D. |
| Carbon Tax | Additional Cost |  | (MMBtu/MWh) is the heat rate of each fossil fuel generator in period *p*. (ton CO2/MMBtu) is the carbon emission factor of each fossil fuel generator in period *p*. ($/ton CO2) is carbon cost per ton of CO2 in period *p*. |
| Sunk |  |  | Sunk costs include operating capital payments for existing generators, transmission systems and existing distribution networks. |

1.2. Constraints

The model has five basic constraints: power balance constraints, conventional unit commitment constraints, generation technology resource constraints, planning and operation marginal reserve constraints, and policy constraints.

Table S1.2. Parameter Descriptions

|  |  |  |
| --- | --- | --- |
| Type | Symbol | Description |
| Set |  | Includes power outputs for each generation projects in each timepoint *t* In load zone *z* and inward transmission flows into that load zone |
| Set |  | Includes load demand and outward transmission flows |
| Set |  | Set of all generators |
| Set |  | A amount of energy injected into load zone *z* through transmission lines from another load zone |
| Set |  | A amount of energy load zone *z* withdraws to other load zones through transmission lines |
| Set |  | Set of all timepoints, indexed by *t* |
| Set |  | Set of all periods |
| Set |  | Set of all days, indexed by *d* |
| Set |  | Set of all load zones, indexed by *z* |
| Set |  | Set of all energy resources, indexed by *f* |
| Set |  | Set of all transmission corridors, indexed by *l* |
| Subset |  | Subset of aggregated generators that have discrete units. |
| Subset |  | Subset of intermittent generators |
| Subset |  | Subset of baseload generators |
| Subset |  | Subset of hydropower generators |
| Subset |  | Subset of storage facilities |
| Subset |  | Subset of generators that can provide reserve capacity |
| Subset |  | Subset of generators that can provide spinning capacity |
| Subset |  | Subset of generators that are located in load zone *b* |
| Subset |  | Subset of generators that are fueled by fossil fuels |
| Subset |  | Subset of generators that are RPS eligible |
| Subset |  | Subset of timepoints when generators may have capacity online |
| Subset |  | Subset of all timepoints in a day |
| Subset |  | Subset of all timepoints in period *p* |
| Subset |  | Subset of fossil-fuel-based resources |
| Subset |  | Subset of non-fossil fuel-based resources |
| Subset |  | Subset of load zones that require planning reserves |
| Parameter |  | Electricity demand in load zone *z* at timepoint *t* |
| Parameter |  | Duration of each timepoint in hours. |
| Parameter |  | Maximum capacity allowed for generator *g* in period *p* |
| Parameter |  | Maximum capacity allowed for transmission corridor *l* in period *p* |
| Parameter |  | Fraction of generator g is expected to be available (used to de-rate for forced outage rate) |
| Parameter |  | Minimum load fraction of generator *g* |
| Parameter |  | Minimum online time once generator *g* stars tup |
| Parameter |  | Minimum offline time once generator *g* shuts down |
| Parameter |  | Maximum ramp up capacity of generator *g* |
| Parameter |  | Maximum ramp down capacity of generator *g* |
| Parameter |  | Capacity factor of generator *g* in timepoint *t* |
| Parameter |  | Minimum load level of hydropower generator *g* in a day *d* |
| Parameter |  | Average load level of hydropower generator *g* in a day *d* |
| Parameter |  | Maximum charge rate for storage *g* |
| Parameter |  | Maximum state of charge of storage facility *g* in timepoint *t*, MWh |
| Parameter |  | Fraction of capacity which can be provided as reserve for generator *g* at timepoint *t*. This parameter is defaulted as 1.0 for fossil fuel generators, and capacity factor for intermittent generators. |
| Parameter |  | Planning reserves requirement for timepoint *t*. It is 0.15 by default for all timepoints. |
| Parameter |  | Annual CO2 emissions limits for power system in period *p* |
| Parameter |  | Fuel requirement of generator *g* for providing spinning reserve, in MMBtu/MW |
| Parameter |  | Fuel requirement of generator *g* for startup, in MMBtu/MW |
| Parameter |  | Fraction of total demand that must come from RPS-eligible generators |
| Parameter |  | Available fraction of transfer capacity for transmission corridor in period *p* |
| Variable |  | Integer variable for commitment capacity of generator *g* in timepoint *t* |
| Variable |  | The commitment capacity of generator *g* in timepoint *t* |
| Variable |  | Additional commitment capacity of generator *g* in timepoint *t* |
| Variable |  | Additional decommitment capacity of generator *g* in timepoint *t* |
| Variable |  | Amount of charge power for generator *g* in timepoint *t* |
| Variable |  | State of charge of storage facility *g* in timepoint *t*, MWh |
| Variable |  | How much spinning up reserve capacity can be provided by generator *g* at timepoint *t* |
| Variable |  | How much spinning down reserve capacity can be provided by generator *g* at timepoint *t* |
| Variable |  | Rate of use of fuel *f* by generator *g* during timepoint *t*, in MMBtu |
| Variable |  | Transmission power from load zone *a* to load zone *b* at timepoint *t* |
| Variable |  | Additional transfer capacity added for local transmission and distribution |
| Variable |  | Power withdrawal from load zone *z*’s central node at timepoint *t* |
| Variable |  | Power injected in load zone’s local node at timepoint *t* |

**1.2.1. Power Balance Constraints**

This expression defines the power balance requirement for the power system. The power injections and withdrawals in each load zone must be equal during the same timepoint.

**1.2.2. Investment Constraints**

This part defines the resource constraints of each type of generating technology in the future according to the resource potential, technology development, land uses and policy targets et al.

Generator constraints (1.2) indicate cumulative capacity limits for resource-constrained generator *g* in period *p*. Transmission constraints (1.3) indicate maximum allowed transmission expansion for transmission corridor *l* in period *p*.

**1.2.3. Operation Constraints**

1.2.3.1. Unit Commitment

This section defines a linear unit commitment for dispatchable generators.

where Equation (1.4) defines commitment capacity by unit level for aggregated generators. Equation (1.5) represents maximum capacity that can be committed. Equation (1.6) defines minimum and maximum output limits for committed capacity. Equation (1.7) represents the consistency of commitment capacity. Equation (1.8-1.9) enforces minimum online and minimum offline times of generators. Equation (1.10-1.11) limits ramp up and ramp down capacity of generators. The corresponding startup, shutdown and maintenance costs of generators will be added into the objective function.

1.2.3.2. Intermittent generators

Intermittent generators like solar and wind produce power according to their capacity factor, de-rated by their forced outage rate. These outputs of generators can be curtailed if the amount of power exceeds the electricity demand.

1.2.3.3. Baseload generators

Baseload generators that do not change their outputs quickly, such as nuclear, geothermal, biomass, biogas and cogeneration, must produce the amount of power of nameplate capacity, de-rated by their forced and scheduled outage rates.

1.2.3.4. Hydropower generators

Hydropower generators that are bigger than 50 MW provide capacity for daily reserves. Small hydro power plants that are run-of-river are regarded as intermittent generators. The outputs of hydropower generators must exceed minimum load level at all timepoints and equal average load level during a day:

1.2.3.5. Storage

Storage facilities, including hydro pumped power plants, lithium-ion, flow-battery, NAS-battery and fly wheel, can charge and discharge power over time.

1.2.3.6. Planning reserve constraints

A planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon. The SWITCH model assigns a 15 percent reserve margin for a predominately thermal system. All generators can provide a reserve margin based on their available capacity in each timepoint1, but the storage is credited based on its net output (discharging power minus charging power) at a specific timepoint.

1.2.3.7. Operation reserve constraints

Spinning reserves track the state of unit commitment and dispatched capacity to ensure that the generation fleet has enough up- and down- ramping capacity to satisfy reserve requirements. The spinning capacity requirements and quick start capacity requirements are based on a heuristic of 3% of load plus 5% of renewable output, according to NREL's 2010 Western Wind and Solar Integration study.

**1.2.4. Carbon Emission Constraints**

This section defines CO2 emission constraints from the power system that generates and transmission energy to meet electricity demand over time. CO2 emissions come from coal-fired power plants and gas-fired power plants for power generation, spinning reserves, and generator startup and energy losses of transmission through electricity transmission lines. The annual CO2 emissions constraints are formulated below:

**1.2.5.** **Transmission and Distribution Dispatch**

1.2.5.1. Transmission Dispatch

This expression defines transmission dispatch constraints that are represented as a transportation model.

1.2.5.2. Local Transmission and Distribution Dispatch

Local transmission and distribution are used to represent the local transmission losses and costs in a load zone. The SWITCH model defines each load zone as having one central node, within which all generators and electricity demand are concentrated. Local transmission and distribution create a virtual local node that connects the central node, and all the generation that comes from the central node and all transmission energy that comes from other load zones will be injected in this virtual local node, considering local transmission loss. The transfer capacity of a local node decides how much energy can be transferred from the central node, so the transfer capacity of a local node may need additional capacity to meet electricity demand in the future. Maximum peak demand is used to represent maximum electricity demand in a period that must be met by the local node.

**2. Update to SWITCH-China model**

**2.1. Fossil fuel power plants**

**2.1.1. Coal-fired power plants**

Generation capacity of operating coal-fired power plants reach roughly 1040 GW by 2019, ranging from 30 MW to 1000 MW for unit size2 (Table S2.1). The wide distribution of unit sizes and build year impacts efficiency of coal fleets. Small coal fleets with less than 300 MW account for 11.6% (Table S2.2). Thus, we summarize seven thermal units based on the unit size with 30 MW, 50MW, 100MW, 200MW, 300MW, 600MW, 1000MW combined with cogeneration generators. The corresponding characteristics, such as heat rate, lifetime, forced outage rate, scheduled outage rate, minimum load fraction, startup fuel, startup cost and minimum on and off time and are same with Li et al3. We apply a performance penalty to older and smaller coal fleets in order to represent the difference in heat rate due to different plant ages and unit sizes2 (Table S2.3).

1. The Cumulative Installed Capacity by Energy Source in 20204

|  |  |  |
| --- | --- | --- |
| Technology | CEC Capacity (GW) | SWITCH Capacity (GW) |
| Coal | 1,079 | 1,040 |
| Onshore wind | 281 | 204 |
| Offshore wind | 8.9 | 5.9 |
| Solar | 253 | 204 |
| Gas | 98 | 90 |
| Nuclear | 48 | 48 |
| Storage | 31 | 30 |
| Hydro | 339 | 326 |

1. Summary of Coal-fired Power Plants by Generation Capacity in 2018

|  |  |  |
| --- | --- | --- |
| Unit Size (MW) | Capacity (MW) | Ratio (%) |
| Unit<100 | 25 | 2.5 |
| 100≤ Unit <200 | 50 | 5.1 |
| 200≤ Unit <300 | 39 | 4.0 |
| 300≤ Unit <600 | 378 | 38.3 |
| 600≤ Unit <1000 | 372 | 37.7 |
| 1000≤ Unit | 122 | 12.4 |

1. The Performance Penalty to Older and Smaller Coal Fleet

|  |  |  |  |
| --- | --- | --- | --- |
| Age | 0-349 MW | 350-449 MW | 450 + MW |
| 0 - 9 years | 20% | 10% | 0% |
| 10 -19 years | 30% | 20% | 10% |
| 20 - 29 years | 40% | 30% | 20% |
| 30 + years | 45% | 35% | 25% |

2.1.1.1. Carbon emission factors

Individual emission factors are developed for each power station configuration. The emission factors of generators can be calculated as follows:

Where, is the emission factor, (kg CO2/kWh); is heat rate, (MMBtu/MWh); is the average carbon content of fuel, (kg CO2/MMBtu). The average carbon content of coal is 95.36 kg/MMBtu5. This is consistent with theoretical emission factors of coal-fired power plants, ranging from 0.746 kg CO2/kWh to 0.9510 kg CO2/kWh due to different unit size reported in the China Electricity Council6 (Table S2.4).

The fuel usage rate is different due to operation conditions, e.g. full-load and load-following operation. It is assumed that fuel requirements for most generators can be approximated very well using a simple proportionality between fuel usage and power production.

1. Emission Factors of Coal Fleets

|  |  |  |  |
| --- | --- | --- | --- |
| Unit Size (MW) | Net coal consumption rate (g/kWh)1 | Emission factor  (kg CO2/kWh) | Heat Rate (MMBtu/MWh) |
| Unit≤100 | 363 | 0.9511 | 9.9730 |
| 100< Unit ≤200 | 320 | 0.8384 | 8.7919 |
| 200< Unit ≤300 | 313 | 0.8201 | 8.5996 |
| 300< Unit ≤600 | 307 | 0.8043 | 8.4348 |
| 600< Unit ≤1000 | 305 | 0.7991 | 8.3798 |
| 1000< Unit | 285 | 0.7467 | 7.8303 |
| IGCC2 | 255 | 0.6681 | 7.0058 |

Note:

1. Net coal consumption rate: the amount of coal used by an electricity generator to generate per kWh electricity;

Burning a ton standard coal in industrial boilers will produce 2620kg CO2, 8.5kg SO2 and 7.4kg NOx, (kg CO2/ SO2 / NOx /ton coal).

2. China HUANENG Group CO., LTD (2012). The introduction of IGCC in Tianjin. Online available: <http://www.chng.com.cn/n31539/n808901/n808904/n808911/c814915/content.html>

2.1.1.2. Clustering method

In order to improve the computational performance of the SWITCH-China models coupling with planning and dispatching stages, we aggregated coal-fired power plants to the power plant level by aforementioned unit sizes, build year, city and heat rate thresholds7. Firstly, all units are aggregated to the power plant level, decreasing from 2932 units to 1356 power plants, in which some units belonging to one power plant are not able to be aggregated to one plant because of different build years. Province and city are location thresholds for all power stations. Then, all units in the same city and same commitment year smaller than the threshold are aggregated to the closest size threshold (either above or below). The final heat rate of aggregated plants is calculated by their weighted average of heat rate in order to maintain an accurate resolution. It is noted that coal-fired plants may consist of as many as 5 similarity unit. For example, a power plant with 5200MW units will behave the same as a separate 1200MW unit in terms of flexibility, heat rate and so on.

**2.2. Renewable power plants**

**2.2.1. Hydro power plants**

Hydropower plants datasets were obtained from the Large Dam Safety Supervision Center8, and includes plant name, generation capacity, build year, annual generation, geographic location, et al. The number of big power plants above 50 MW is 279 hydropower units, accounting for 86% of total hydropower capacity (total 326GW in 2019). Small hydropower plants only account for a small part of total hydropower capacity, and thus we cluster hydropower plants less than 50 MW to one big generator in the same build year by province, in order to improve computation performance.

**2.2.2. Wind power plants**

Existing onshore wind power plants with capacity, geographical locations, number of turbines and installation year in China are obtained from the UNEP DTU PARTNERSHIP9. Existing onshore wind farms by 2019 in China account for 204 GW, and those from the UNEP data sum up to 84 GW with 1517 projects, accounting for 41.2% of total wind farm capacity. I To match the installed capacity between our collected data and reported installed capacity at the provincial level in 201910, we add assumed power plants to represent the remaining wind capacity by province. Offshore wind farm information is obtained from 4COffshore11, which includes existing and under-construction offshore wind. The existing capacity of offshore wind farms by 2019 was 5.9 GW.

**2.2.3. Solar power plants**

The capacity of solar PV grew from 0.8 GW in 2010 to 204 GW in 20194,12.

**2.2.4. Generation profile of wind, solar, and hydro**

Hourly capacity factors of wind and solar power plants comes from He et al13,14. We consider three technologies: distributed PV, central PV and commercial PV. Hydropower potential by province is developed by the China Society for Hydropower Engineering15. Historical monthly hydropower productions are used to bound minimum and maximum power outputs16. The national average capacity factor and provincial average capacity factor of solar PV, onshore wind, hydro, and offshore wind are shown in Table S2.5.

Wind Resources:

Hourly wind outputs for each load area were obtained from He et al14 with 3TIER hourly wind speed data. All of the wind points within China are aggregated into 200 wind farms. The power output for each wind site is averaged over the hour of each timestamp. Then these hourly averages are interpolated and again averaged over each group of aggregated wind sites to create the hourly output of new wind farms.

Solar Resources:

Hourly solar outputs for each load area were obtained from He et al13 with 3TIER hourly solar irradiation data. All of the solar points within China are aggregated into 200 solar farms. The power output for each solar site is averaged over the hour of each timestamp. Then these hourly averages are again averaged over each group of aggregated solar sites to create the hourly output of new solar plants.

The average capacity factors of solar and wind of each province are validated to match provincial average capacity factors of solar and wind according to the NEA17 (Table S2.5).

1. National Average Capacity Factor by Generation Technology

|  |  |
| --- | --- |
| Technology | Capacity factor |
| Onshore wind | 0.227 |
| Offshore wind | 0.341 |
| Solar PV | 0.137 |
| Hydropower | 0.446 |

**2.3. Transmission network**

**2.3.1. Transmission systems**

The spatial resolution of the SWITCH-China model is on the provincial level, so we model the transmission corridors on the inter-provincial/regional level between the central nodes (capital cities) of these provinces. We do not model the local transmission and distribution networks, but we do consider transmission losses and costs. Ultra-high-voltage (UHV) electricity transmission lines with ≥ 800kV for DC or ≥ 1000 kV for AC in 2019 used in the SWITCH-China model are obtained from the State Grid18, China Southern Power Grid19, and the China Electricity Council4 (Table S2.6; Table A1). High voltage transmission lines rated at 750 kV are only built for the Northwest power grid. Interprovincial transmission lines rated at 500kV are between 4000 MW-7500MW4,20.

As shown in Table S2.6, the statistical error in the modeled transmission lines mainly comes from 500kV based transmission lines, as we model the transmission corridors on the interprovincial/regional level between the central nodes (capital cities) of these provinces. The local transmission and distribution networks are used in the SWITCH-China model to simulate the transmission losses and costs of provincial transmission lines.

Additionally, some assumptions are listed:

(1) All transmission lines rated at 330 kV, and 220 kV transmission lines are plant connections or short intra-provincial lines;

(2) DC transmission lines connect two load areas point-to-point;

(3) UHVAC transmission lines connect several load areas that are between the original sending load area and ending load area;

(4) Each load area has electricity connections with its neighbor load area via 500 kV transmission lines plus existing UHV lines;

(5) The capacity of the transformer substation is assumed to be 1.4 times bigger than the capacity of transmission lines, considering the redundancy and reliability of the power system.

1. Cumulative Capacity and Length of Transmission Lines above 220kV in 2017

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Voltage Level (kV) | CEC, 2018 | | SWITCH | |
| Length (104m) | Capacity (108kVA) | Length (104m) | Capacity 108kW |
| 1000 | 1.0 | 1.6 | 1.03 | 0.91 |
| ±800 | 2.1 | 1.1 | 2.9 | 1.3 |
| 750 | 1.9 | 1.5 | 0.6 | 0.19 |
| 500 | 17.3 | 14.4 | 0.56 | 0.10 |
| ±500 | 1.4 | 1.9 | 0.54 | 0.19 |
| 330 | 3.0 | 1.3 | - | - |
| 220 | 41.5 | 20.3 | - | - |
| Total 220kV above | 68.6 | 40.3 | - | - |
| Total 500kV above | 23.7 | 20.5 | 7.3 | 4.8 |

**2.3.2. Transmission costs**

The capital cost of transmission line expansion depends on the type and configuration of new equipment, new conductors, and additional land. The capital cost of transmission lines varies with power and distance21:

where is the capital cost of substation ; is substation capacity. is the capital cost of transmission line distance, ; is distance of transmission line.

Power-related costs are based on the sizing requirements for new AC voltage transformer stations or AC-DC and DC-AC converter stations. Distance-related costs are due to conductors, land use, and electricity lines, as shown in Table S2.7. Regional differences in economics reflect capital costs of transmission lines and substations, as shown in Table S2.8.

1. Capital cost for Different Types of Transmission Lines22

|  |  |  |  |
| --- | --- | --- | --- |
| Type | Transmission line cost ($/km) | Substation cost ($/MVA) | Transmission-capacity cost($/MVA-km) |
| AC-110kV | 101,000 | 44,000 | 1857 |
| AC-220kV | 174,000 | 33,000 | 1042 |
| AC-330kV | 161,000 | 31,000 | 414 |
| AC-500kV | 424,000 | 22,000 | 298 |
| AC-750kV | 367,000 | 20,000 | 171 |
| DC-500kV | 377,000 | 105,000 | - |
| HVAC-1000kV | 1238,000 | 53,000 | - |
| HVDC-±800kV | 665,000 | 103,000 | - |

1. Capital Cost of Transmission Line Size by Region Power Grid (RMB /km)22

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Regional power grid | 110 kV | 220 kV | 330 kV | 500 kV | 750 kV |
| North | 60 | 130 | - | 340,000 | - |
| Northeast | 58 | 85 | - | 300,000 | - |
| Northwest | 54 | 105 | 109 | - | 364,000 |
| East | 88 | 148 | - | 507,000 | - |
| Central | 63 | 120 | - | 443,000 | - |
| South | 75 | 121 | - | 371,000 | - |
| Inner Mongolia | 51 | 100 | - | 220,000 | - |

**2.3.3. Transmission losses**

Loss rates from transmission include transformer substation losses, overhead lines losses and corona losses. Loss rates of overhead lines vary by transfer capacity and distance. Loss rates of transmission can be calculated under different situations. HVDC transmission has 30-50% less transmission losses than comparable alternating current overhead lines. (For example, given 2500 MW transmitted power on 800 km of overhead lines, the losses with a conventional 400-kv AC line are 9.4%; with HVDC transmission at 500 kV, they are only 6%, and at 800 kV HVDC they are just 2.6%.). Table A2 shows that realistic transmission losses of high voltage transmission lines from 2011 to 2013, in which it includes ±500 kV, 500 kV, ± 800 kV and 1000 kV transmission lines23. We summarize the relationship between transmission line length, capacity and loss rate according to literature6,20,23 (Table S2.9). For the same voltage level, the transmission losses will increase as transmission distance increases (Table A3). For ± 800kV transmission lines, such as the Jing-Su UHVDC line from Sichuan to Jiangsu with a 2090 km length, the transmission losses are 7.0% at full load23. For other voltage level transmission lines with other voltage levels, we take an average value given the same transmission line length. We use linear interpolation to fill in the missing values.

1. Transmission Line Losses for Different Voltage Levels and Transmission Distances

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Transmission distance (km) | 1000 kV (%) | ± 800 kV | ±500 kV (%) | 500 kV (%) |
| ≤200 | 0.70 | 0.85 | - | 1.58 |
| ≤400 | 1.15 | 1.45 | - | 2.62 |
| ≤600 | 1.66 | 2.12 | 3.0 | 3.92 |
| ≤800 | 2.18 | 2.65 | - | 4.15 |
| ≤1000 | 2.71 | 3.31 | 7.5 | 5.15 |
| ≤1500 | - | 3.50 | 7.5 | - |
| ≤2000 | - | 7.00 | - | - |

Note: It is assumed that all transmission lines work in full load.

**2.4. Capital costs**

The global weighted-average LCOE of solar, onshore wind, offshore wind and battery storage in 2018 was 77%, 35%, 20%, and 85% lower than in 2010, respectively. The overnight costs of renewable generation technologies and storage in 2019 are derived from the IRENA24 and the Annual Technology Baseline (ATB) from NREL25. Capital cost projections of renewable generation technologies come from the State Grid Energy Research Institute26, IRENA24, and ATB data25 (Table S2.10). Two scenarios regarding capital cost projections for solar, onshore wind, and offshore wind comes from the State Grid Energy Research Institute26. Overnight cost projections of electricity storage are derived from ATB data25. The other generation technologies are obtained from the China Electricity Council4, State Grid Energy Research Institute26, and the China Electric Power Planning & Engineering Institute22(Table S2.11).

1. Capital Costs of Renewable Generation Technologies and Storage ($/kW)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Scenario | Technology | 2019 | 2020 | 2025 | 2030 |
| Low cost | Solar ($/kW) | 794 | 765 | 624 | 483 |
| Onshore wind ($/kW) | 1222 | 1187 | 1015 | 843 |
| Offshore wind ($/kW) | 3012 | 2827 | 2186 | 1564 |
| Storage ($/kW) | 276 | 215 | 139 | 101 |
| Storage ($/kWh) | 317 | 230 | 160 | 116 |
| Moderate cost | Solar ($/kW) | 794 | 770 | 652 | 534 |
| Onshore wind ($/kW) | 1222 | 1192 | 1043 | 895 |
| Offshore wind ($/kW) | 3012 | 2917 | 2442 | 1967 |
| Storage ($/kW) | 276 | 260 | 179 | 146 |
| Storage ($/kWh) | 317 | 299 | 206 | 168 |

1. Capital Costs of Generation Technologies ($/kW)22

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Technology | 2016 | 2020 | 2025 | 2030 |
| Coal | 530 | 530 | 530 | 530 |
| Gas | 490 | 490 | 490 | 490 |
| Nuclear | 1976 | 2721 | 2721 | 2721 |
| Hydro power | 1410 | 1710 | 1710 | 1710 |
| Hydro pumped ($/kW) | 577 | 860 | 860 | 860 |
| Hydro pumped ($/kWh) | 170 | 255 | 255 | 255 |
| Geothermal | 3900 | 3700 | 3515 | 3339 |
| Biomass | 2105 | 2000 | 1901 | 1807 |

The annual cost of power plants is formulated as follow:

where is the total annual cost of projects in year . is the sunk cost of existing power plants. is the overnight cost of power plants in year . is the newly installed capacity of power plants in year . is a function returning the capital recovery factor. The discount rate is assumed to be 7%27.

The lifetime of offshore wind power plants, onshore wind power plants, and solar PV power plants is assumed to be 20 years (Table S2.12).

1. Lifetimes of various types of Generation Technologies

|  |  |  |
| --- | --- | --- |
| Generation technology | Lifetime |  |
| Onshore wind | 20 | Assumptions in this study |
| Offshore wind | 20 |
| Solar Photovoltaic | 20 |
| Hydropower | 100 | U.S. Regional Energy Deployment System (ReEDS) Model: Version 201627 |
| Hydro pumped | 60 |
| Gas | 30 |
| Battery Storage | 15 |
| Coal | 30 | SWITCH-China model3 |
| Nuclear | 60 |

**2.5. Fuel price**

The average national fuel costs of coal and gas used in the SWITCH-China model were $2.99/MMBtu and $6.57/MMBtu in 2018, respectively28,29. Prices of coal and natural gas by province are derived from resources28,29. Forecasted prices of coal and natural gas increase to be $3.29/MMBtu and $9.53/MMBtu, respectively30,31. The uranium price is $0.64/MMBtu in 2019 and grows to $0.66/MMBtu in 203025.

By 2019, there were 21 LNG terminals in operation across China, with an aggregate annual receiving capacity of over 80 million tons (about 108 billion m3)32. There are three pipelines, namely the Central Asia-China gas pipeline33, the China-Russia East pipeline34, and the China-Myanmar pipeline35, importing about annual 52 billion m3 natural gas in 2018, accounting for about 40% of total natural gas imports32. China’s natural gas consumption has increased by about 60% (2010-2018)32. A World Energy Outlook report projected that China will import almost 60% natural gas of total natural gas consumption by 204036. Thus, we introduced a supply constraint on natural gas according to the World Energy Outlook report36. According to the report, China’s natural gas demand will be 533 billion m3 by 2030 under the stated policies scenario. The net imports natural gas will be 286 billion m3, accounting for 53% of the demand. The share of natural gas that is used to produce electricity generation will be about 32% by 2040. The share of natural gas that is used to produce electricity generation was 17.3% in 2019. We used linear interpolation to project its share in 2030. It is reasonable to assume that the maximum share of natural gas that is used in power sector is 24.95%, and that the supply constraint on natural gas is 133 billion m3 by 2030.

**2.6. CO2 emissions constraints assumptions**

Carbon cap constraints (C70) implies a carbon cap of 70% lower than the 2014 emissions level by 203037–39.

1. Carbon Emissions Constraints of the Power System (million tons CO2)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Scenario | 2014 | 2020 | 2025 | 2030 |
| C70 | 4416 | 3590 | 3090 | 1310 |

**2.7. CO2 accounting**

The carbon content of coal and natural gas is 0.09552 tonCO2/MMBtu, and 0.05306 ton CO2/MMBtu, respectively5. The total emissions of the power system are the sum of plant level emissions from generation and spinning reserves and must not exceed the carbon emission constraints as shown in Table S2.12.

**2.8. Electricity demand assumptions**

We collected a range of long-term demand forecasts from Chinese companies, international organizations, and related reports (Table S2.14). The electricity demand in 2020 was 7510 TWh40. The electricity consumption by province in 2030 was determined using a log-linear regression model following the method in Lin et al41,42. This model considers electricity consumption as a function of provincial gross domestic product (GDP), population, and the percentage of total value added by tertiary industry out of total provincial GDP (tertiary share). It assumes that the average annual growth rate of GDP in each province from 2016 to 2020 follows the goal described in China's 13th Five-year Plan (FYP) for that province41,42. It then assumes that the average annual growth rate from 2021 to 2030 is half of that from 2016 to 2020. For provincial population, it projects population in 2020 based on each province's 13th FYP and then assumes that, from 2021 to 2030, the population grows at half the rate assumed towards 2020. The electricity demand in 2030 will be 9,381 TWh, which is close to other forecasts for 2030.

The method of modeling load consumption using a time series followed the method described in Li et al3. As stated, province-wide electricity consumption patterns vary dramatically with the climate, economy, and geography of each province. However, there are also seasonal, intra-week, and intra-day variations in demand, which we consider in our study. Firstly, monthly national electricity demand and daily electricity demand are derived from the NDRC43 to model seasonal and intra-day variations in electricity demand by province. Each province uses the same monthly and daily electricity profiles up to 2030 to simplify the computation. Finally, hourly demand by province is calculated based on national electricity demand projections, typical yearly load profiles, and typical hourly load profiles.

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1. Long-term Electricity Demand Forecasts (TWh)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | 2018 | 2020 | 2025 | 2030 |
| LBNL(Low demand)44 | - | 7085 | 8028 | 8875 |
| LBNL(High demand)44 | - | 7085 | 8427 | 9664 |
| State grid energy research institute (SGERI26) | 6900 | 7600 | 9100 | 10600 |
| He et al,.45 | - | 6900 | 8298 | 9381 |
| IEA38 | - | - | 8555 | 9686 |
| This study | - | 7510 | 8298 | 9381 |

**2.9. Offshore wind generation plan from 2021 to 2030**

Table S2.15 shows the coastal province plans for offshore wind generation (2021 - 2030). Most coastal provinces released offshore wind or wind plans up to 2025. Based on authorized renewable energy installed capacity plans from the Jiangsu, Guangdong, and Zhejiang provinces, their newly added offshore wind will reach 31.5 GW by 2025. Guangdong province plans to install 15 GW offshore wind between 2026 and 2030. Shandong is planned to install the offshore wind capacity of 12.75 GW by 2035. Fujian, Liaoning, Tianjin, Hebei, Shanghai, Guangxi, and Hainan provinces either have not released offshore wind plans or do not specify onshore wind and offshore wind in their “14th Five-Year” plans. It is reasonable to assume that these provinces’ offshore wind plans between 2020 and 2030 are the same as the plan between 2016 and 2020. It is assumed that Jiangsu and Zhejiang provinces keep the same plans between 2026 and 2030. The total planning installed offshore wind capacity is from 2021 – 2030 is about 78 GW. Further, the offshore wind capacity plan is planned to 5GW by 2020 according to the national “13th Five-Year” plan1.

Based on the above discussion, the cumulative offshore wind capacity will reach about 83 GW by 2030. This value is set to be the capacity upper limit in the C70-LO scenario.

1. The offshore wind plan of coastal provinces in China (GW)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Province | 2016-2020 | 2021 - 2025 | 2026-2030 | Plan (2021-2030) |
| Liaoning | 0.346 | 3.3 (onshore wind)47 | - | 0.6 |
| Tianjin | 0.1948 | 0.78 (wind)49 | - | 0.38 |
| Hebei | 0.850 | 5.2 (wind)51 | - | 1.6 |
| Shandong | 1.452,53 | 12.75 by 203552,53 | | 8.5 |
| Jiangsu | - | 1254 | - | 24 |
| Zhejiang | - | 4.555 | - | 9 |
| Shanghai | 0.4656,57 | - | - | 0.96 |
| Fujian | 258 | - | | 4 |
| Guangdong59 | - | 15 | 15 | 30 |
| Guangxi60 | 3 (onshore wind) | - | - | 0.6 |
| Hainan | 0.39561 | 5 (Solar and offshore wind)62 | - | 0.79 |
| Total |  |  |  | 77.43 |

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Appendix

1. Transmission lines above 500 kV by the end of 2019

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| No. | Name | Operation | Type | Sending | Ending | Voltage | Distance (km) | Investment (billion $) | Capacity (MW) |
| 1 | Xiangshang | 2011 | DC | Sichuan | Shanghai | 800 | 2034 | 0.356728571 | 6400 |
| 2 | Jinsu | 2012 | DC | Sichuan | Jiangsu | 800 | 2095 | 0.416914286 | 7200 |
| 3 | Hazheng | 2013 | DC | Xinjiang | Henan | 800 | 2210 | 0.334185714 | 8000 |
| 4 | Binjin | 2014 | DC | Sichuan | Zhejiang | 800 | 1680 | 0.340785714 | 8000 |
| 5 | Lingshao | 2016 | DC | Ningxia | Zhejiang | 800 | 1722 | 0.3851 | 8000 |
| 6 | Jindongnan-Jinmen | 2009 | AC | Shanxi | Hubei | 1000 | 640 | 0.146942857 | 5000 |
| 7 | Ximeng-Shandong | 2016 | AC | East\_Inner\_Mongolia | Shandong | 1000 | 730 | 0.386714286 | 7350 |
| 8 | Mengxi-Tianjin South | 2016 | AC | West\_Inner\_Mongolia | Tianjin | 1000 | 608 | 0.250285714 | 8000 |
| 9 | Huaihu | 2013 | AC | Anhui | Shanghai | 1000 | 656 | 0.272857143 | 6500 |
| 10 | Zhefu | 2014 | AC | Fujian | Zhejiang | 1000 | 603 | 0.269571429 | 6600 |
| 11 | Ningdong | 2011 | DC | Ningxia | Shandong | 660 | 1333 | 0.148357143 | 4000 |
| 12 | Hengyu-Weifang | 2017 | AC | Shaanxi | Shandong | 1000 | 1048 | 0.345428571 | 6500 |
| 13 | Jiuquan-Hunan | 2017 | DC | Gansu | Hunan | 800 | 2383 | 0.374285714 | 8000 |
| 14 | Jinbei-Jiangsu | 2017 | DC | Shanxi | Jiangsu | 800 | 1119 | 0.231428571 | 8000 |
| 15 | Ximeng-Taizhou | 2017 | DC | East\_Inner\_Mongolia | Jiangsu | 800 | 1620 | 0.362857143 | 10000 |
| 16 | Shanghaimiao-Shandong | 2017 | DC | West\_Inner\_Mongolia | Shandong | 800 | 1238 | 0.315714286 | 10000 |
| 17 | Ximeng-Shengli | 2017 | AC | East\_Inner\_Mongolia | Shandong | 1000 | 730 | 0.0708 | 6500 |
| 18 | Zhalute-Qingzhou | 2017 | DC | East\_Inner\_Mongolia | Shandong | 800 | 1234 | 0.315714286 | 10000 |
| 19 | Zhundong-Wannan | 2018 | DC | Xinjiang | Anhui | 1100 | 3324 | 0.581428571 | 12000 |
| 20 | Sutong GIL | 2019 | AC | Jiangsu | Shanghai | 1000 | 5.5 | 0.068042857 | 6500 |
| 21 | Beijing West-Shijiazhuang | Under construction | AC | Beijing | Hebei | 1000 | 228 | 0.049571429 | 6500 |
| 22 | Weifang-Linyi-Zaozhuang-Heze-Shijiazhuang | 2019 | AC | Shandong | Hebei | 1000 | 823.6 | 0.208971429 | 6500 |
| 23 | Mengxi-Jinzhong | 2019 | AC | East\_Inner\_Mongolia | Shanxi | 1000 | 304 | 0.070785714 | 6500 |
| 24 | Qinghai-Henan | Under construction | DC | Qinghai | Henan | 800 | 1587 | 0.322857143 | 8000 |
| 25 | Shanbei-Hubei | Under construction | DC | Shaanxi | Hubei | 800 | 1136 | 0.254857143 | 10000 |
| 26 | Nuozhadu-Jiangmen | 2014 | DC | Yunnan | Guangdong | 800 | 1413 | 0.218571429 | 5000 |
| 27 | Yunguang-Guangdong | 2010 | DC | Yunnan | Guangdong | 800 | 1373 | 0 | 5000 |
| 28 | Xiluodu-Guangdong | 2013 | DC | Yunnan | Guangdong | 500 | 1223 | 0.227 | 6400 |
| 29 | Jinzhong-Guangxi | 2016 | DC | Yunnan | Guangxi | 500 | 1105 | 0 | 3200 |
| 30 | Guiguang2-Guangdong | 2007 | DC | Guizhou | Guangdong | 500 | 1194 |  | 3000 |
| 31 | Guiguang-Guangdong | 2004 | DC | Guizhou | Guangdong | 500 | 891 |  | 3000 |
| 32 | TianGuang-Guangdong | 2001 | DC | Guangxi | Guangdong | 500 | 963 |  | 1800 |
| 33 | ShiXianshang-Guangdong | 2008 | AC | Guizhou | Guangdong | 500 | 1240 |  | 5000 |
| 34 | GuiGuangAC-Guangdong | 2003 | AC | Guizhou | Guangdong | 500 | 900 |  | 1500 |
| 35 | TianGuangAC1-Guangdong | 1993 | AC | Guangxi | Guangdong | 500 | 935 |  | 800 |
| 36 | TianGuangAC2-Guangdong | 1998 | AC | Guangxi | Guangdong | 500 | 939 |  | 800 |
| 37 | TianGuangAC3-Guangdong | 2002 | AC | Guangxi | Guangdong | 500 | 765 |  | 800 |
| 38 | TianGuangAC4-Guangdong | 2005 | AC | Yunnan | Guangdong | 500 | 853 |  | 1320 |
| 39 | Dianxibei\_Gunangdong | 2017 | DC | Yunnan | Guangdong | 800 | 1960 |  | 5000 |
| 40 | Jinzhong-Guangxi | 2017 | DC | Yunnan | Guangxi | 800 | 1116 |  | 3200 |
| 41 | Wudongde-Guangxi1\_Guangdong | 2017 | DC | Yunnan | Guangxi | 800 | 900 |  | 3000 |
| 42 | Wudongde-Guangxi2\_Guangdong | 2017 | DC | Guangxi | Guangdong | 800 | 500 |  | 5000 |
| 43 | Xiluodu-Zhexi | 2014 | DC | Yunnan | Zhejiang | 800 | 1653 | 3.35 | 7500 |
| 44 | Huainan-Zhebei-Shanghai | 2013 | AC | Anhui | Shanghai | 1000 | 649 |  | 6500 |
| 45 | Gezhouba-Shanghai | 2010 | DC | Hubei | Shanghai | 500 | 1109 |  | 3000 |
| 46 | Longquan-Zhengping | 2002 | DC | Hubei | Jiangsu | 500 | 860 |  | 3000 |
| 47 | Yihua DC | 2006 | DC | Hubei | Shanghai | 500 | 1049 |  | 3000 |
| 48 | Lingfeng DC | 2011 | DC | Hubei | Shanghai | 500 | 978 |  | 3000 |
| 49 | Jianglingcheng-Echeng | 2003 | DC | Hubei | Guangdong | 500 | 941 |  | 3000 |
| 50 | Jinlijiang - Guangdong | - | AC | Hunan | Guangdong | 500 |  |  | 1800 |
| 51 | Fugu – North grid | 2006 | AC | Shaanxi |  | 500 | 439 |  | 3600 |
| 52 | Deyang - Baoji | 2009 | DC | Sichuan | Shaanxi | 500 | 534 |  | 3000 |
| 53 | Guizhou - Chongqing | - | AC | Guizhou | Chongqing | 500 |  |  | 2000 |

1. 2011-2013 National Inter-Regional and Inter-Provincial Transmission Line Loss Informations23

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Name | Start point – end point | Operation year | Voltage level | Capacity(104kW) | Length(km) | Theory Loss | 2011 | | | 2012 | | | 2013 | | | Type |
| Exported generation(108 kWh) | Imported generation(108 kWh) | Transmission loss | Exported generation(108 kWh) | Imported generation(108 kWh) | Transmission loss | Exported generation(108 kWh) | Imported generation(108 kWh) | Transmission loss |
| 1.Longzhen | Hubei-Jiangsu | 2002.12 | ±500kV | 300 | 860 | 7.5% | 92.3 | 87.7 | 5.08% | 98.7 | 93.3 | 5.43% | 112.6 | 107.0 | 4.94% | DC |
| 2.Genan | Hubei-Shanghai | 2010.04 | ±500kV | 120 | 1109 | 7.5% | 69.8 | 66.6 | 4.51% | 55.2 | 52.4 | 5.00% | 36.3 | 34.6 | 4.91% | DC |
| 3.Yihua | Hubei-Shanghai | 2006.11 | ±500kV | 300 | 1049 | 7.5% | 108.7 | 102 | 6.17% | 123.3 | 115.6 | 6.20% | 102.0 | 96.5 | 5.34% | DC |
| 4.Linfen | Hubei-Shanghai | 2011.03 | ±500kV | 300 | 978 | 7.5% | 35.0 | 33.6 | 4.02% | 70.2 | 66.0 | 5.89% | 55.5 | 52.7 | 5.13% | DC |
| 5.Yindong | Ningxia-Shandong | 2011.02 | ±660kV | 400 | 1333 | 7.0% | 256.6 | 243 | 5.31% | 280.6 | 266.5 | 5.02% | 284.3 | 268.3 | 5.61% | DC |
| 6.Fufeng | Sichuan-Shanghai | 2009.12 | ±800kV | 640 | 1891 | 7.0% | 56.4 | 53.9 | 4.38% | 144.7 | 137.9 | 4.71% | 320.4 | 299.5 | 6.54% | DC |
| 7.Jingsu | Sichuan-Jiangsu | 2012.12 | ±800kV | 720 | 2090 | 7.0% |  |  |  | 45.0 | 41.5 | 7.66% | 224.6 | 211.2 | 6.00% | DC |
| 8.Lingbao | Shaanxi-Henan | 2002.06 | ±330kV | 111 | 95 | 1.0% | 71.3 | 70.4 | 1.24% | 89.8 | 88.7 | 1.24% | 65.5 | 64.8 | 1.11% | DC |
| 9.Debao | Sichuan-Shaanxi | 2009.12 | ±500kV | 300 | 534 | 3.0% | 100.6 | 97.7 | 2.95% | 125.9 | 121.9 | 3.19% | 131.9 | 128.1 | 2.93% | DC |
| 10.Gaolin | Liaoning -Hebei | 2001.05 | ±500kV | 300 | 204 |  | 101.8 | 100.2 | 1.56% | 110.7 | 109.0 | 1.55% | 181.8 | 178.8 | 1.63% | DC |
| 11.Jiangcheng | Hubei - Guangdong | 2003.10 | ±500kV | 300 | 941 | 7.7% | 140.9 | 133.4 | 5.35% | 156.1 | 147.2 | 5.69% | 126.7 | 120.3 | 5.03% | DC |
| 12.Changnan | Shanxi - Henan | 2009.01 | 1000kV | 500 | 639 | 1.5% | 62.7 | 62.2 | 0.64% | 100.9 | 100.3 | 0.59% | 81.8 | 81.2 | 0.70% | AC |
| 13.Yangcheng - Jiangsu | Shanxi-Jiangsu | 2000.02 | 500kV | 300 | 508 |  | 157.7 | 152.3 | 3.43% | 169.8 | 163.9 | 3.48% | 166.5 | 160.7 | 3.49% | AC |
| 14.Jingjie - Hebei | Shaanxi-Hebei | 2006.08 | 500kV | 360 | 439 | 2.0% | 229.8 | 224.2 | 2.45% | 214.7 | 209.6 | 2.37% | 207.3 | 202.5 | 2.34% | AC |
| 15.Xinheng | Hebei - Henan | 2003.09 | 500kV |  | 69 |  |  |  |  |  |  |  |  |  |  | AC |
| Sum |  |  |  |  | 12739 |  | 1483.6 | 1427.2 | 3.80% | 1785.6 | 1713.8 | 4.02% | 2097.2 | 2006.2 | 4.34% |  |

1. Loss rates of transmission during different situation20

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| Transmission distance (km) | Capacity (MW) | 1000 kV (%) | ± 800 kV | ±500 kV (%) | 500 kV (%) |
| ≤200 | 2800 | 0.62 | - | - | 1.37 |
| 4000 | 0.63 | - | - | 1.83 |
| 5600 | 0.70 | - | - | 1.72 |
| 8000 | 0.84 | - | - | 1.83 |
| 8400 | 0.87 | - | - | 1.58 |
| ≤400 | 2800 | 1.13 | - | - | 2.71 |
| 4000 | 1.15 | - | - | 2.62 |
| 5600 | 1.29 | - | - | 2.71 |
| 8000 | 1.15 | - | - | 2.62 |
| 8400 | 1.16 | - | - | 2.71 |
| ≤600 | 2800 | 1.63 | - | - | 4.06 |
| 4000 | 1.66 | - | - | 3.91 |
| 5600 | 1.87 | - | - | 4.06 |
| 8000 | 1.66 | - | - | 3.92 |
| 8400 | 1.68 | - | - | 3.63 |
| ≤800 | 2800 | 2.14 | - | - | 4.15 |
| 4000 | 2.18 | - | - | 3.86 |
| 5600 | 2.14 | - | - | 4.62 |
| 8000 | 2.18 | - | - | 4.68 |
| 8400 | 2.21 | - | - | 4.84 |
| ≤1000 | 2800 | 2.66 | - | - | 5.15 |
| 4000 | 2.71 | - | - | 4.78 |
| 5600 | 2.66 | - | - | 5.74 |
| 8000 | 2.71 | - | - | 5.81 |
| 8600 | 2.74 | - | - | 5.51 |