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ACCELERATING THE ENERGY TRANSITION: ASSESSING AMBITIOUS SCENARIOS TO MAKE SOLAR POWER A GLOBAL SOLUTION

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Summary

Current climate pledges under the Paris Agreement are not enough to limit global warming to 1.5°C (IPCC, 2018). The Intergovernmental Panel on Climate Change (IPCC) emphasizes that, if we are to meet the climate target, we need to make unprecedented changes to our energy systems, cutting back our carbon dioxide emissions by almost half and greatly expanding renewable energy (IPCC, 2018). "The next few years are probably the most important in our history," cautioned Debra Roberts, chair of IPCC Working Group II (IPCC, 2018). Moreover, scientists state that current and planned policies for renewable energy are insufficient to meet the temperature target and we need to deploy at least six times more renewable capacity than outlined in current plans (IPCC, 2018; IRENA, 2018a). Renewable energy has grown rapidly in recent years, yet we need to deploy renewables faster for an energy transition that attains climate targets, while it aligns with social and environmental objectives including safeguarding affordable energy for all, enhancing energy security, and improving the air we all breathe.

Solar power has enormous untapped potential and is expanding faster than ever: in 2017, the world installed more solar power capacity than coal, gas, and nuclear plants together; and investors dedicated more capital to solar power projects than any other power source–about $161 billion (UNEP, 2018). Indeed, the world is building more solar power plants because they are becoming economically viable. During the last decade, the electricity cost of solar power has fallen faster than ever before, and in some countries, power-purchase agreements for solar photovoltaics projects–contracts between a power generator and a purchaser–fall below 3 cents per kWh, making it competitive in those countries with both old and newly built coal power plants (Bailey, 2018). Despite these bright news, solar power accounts only for 1% of the world's electricity systems, because of insufficient provision of power storage, grid infrastructure, and government support (Mathiesen, 2016). Therefore, if policymakers aim to meet the temperature target, it would be beneficial if they are informed about scenarios that provide strategies to advance the deployment of solar power and to facilitate its integration in existing systems.

Ambitions scenarios to advance and accelerate the deployment of solar power may be valuable for policymakers, given the scale of the global energy transition and the urgency of making it a reality. Hence, in this thesis, I investigate a number of scientific questions, which are united methodologically in terms of their reliance on high resolution modelling, all of which bear on the issue of increasing the rate of investment into solar power by removing specific challenges and barriers for solar power.

I address specific challenges and barriers along three different research questions: China is the world leader in deploying solar photovoltaics capacity; however, it also faces recurrent and severe air pollution episodes. Therefore, how much can the country's solar power generation increase with policies seeking to eliminate country's air pollution? If China largely increases variable solar photovoltaics capacity, what would be required to generate controllable solar power in desert regions and transmit it to distant electricity grids, where most of the population lives? Also, what would be the cost and transmission

requirements of supplying controllable solar power to the consumption centers in the second-largest electricity consumer and carbon emitter after China, the United States? If the temperature target is to be met, it may also be beneficial to deploy affordable solar power in developing countries, yet these countries face a higher number of challenges than developed countries. Therefore, how does the current political, institutional, and economic situation in Africa affect the affordability of controllable and reliable solar power supplied to consumers in sub-Saharan Africa's demand centers?

The three research contributions that comprise this thesis provide insights for policymakers to address specific barriers and challenges for solar power and the benefits that might be accrued from particular policy decisions. In the following, I summarize the findings from the research contributions:

China is taking the lead in solar capacity expansion because of concerns about climate change, air pollution, and its effects on the population's health. *Contribution I* examines the question of how much environmental conditions such as ambient air pollution affect the generation of electricity from solar photovoltaics plants in China and, hence, revenues for solar investors. I examine how much air pollution control measures on fossil fuel sectors, namely, the energy, industrial, transport, and residential and commercial sectors, lead to an increase in surface solar irradiance and, consequently, to the generation of electricity from the current fleet of solar photovoltaics plants. I propose concrete, sector-specific air pollution control strategies, quantify the cost of implementing these strategies, and compare it to the increase in revenues for solar investors. This research combines global aerosol-climate modeling and solar photovoltaics system modeling with present market insights, including project financing, financial incentives for solar photovoltaics generation, and variations in the prospective technological development of solar photovoltaics. The findings show how much solar power generation increases because of reduced emissions from fossil fuel sectors and to what extent revenues for solar investors compensate for the costs of air pollution control measures. By 2040, the revenue gains from increased solar power generation could offset up to about 14–18% of the costs of implementing policies to eliminate emissions in the energy sector. These findings imply that, if the same actors in the energy sector own both coal and solar photovoltaics plants, the implementation of policies to remove emissions might provide an economically salient argument for accelerating improvements in air pollution.

China and the United States are the world's largest energy consumers and the largest greenhouse gas emitters. Therefore, their energy policy choices have great influence on the world's capabilities to limit climate change. If fossil fuel sources find substitutes in carbon-neutral energy sources, among them variable renewable energy, then deploying large amounts of renewable, controllable, and potentially baseload power–electricity supply with a constant output throughout the year–might be especially valuable. Concentrating solar power equipped with thermal storage can store heat during the daytime and convert it into electricity when needed the most. Concentrating solar power is most suitable for desert regions with high irradiation levels; however, these regions are usually far from high-consumption centers, requiring the construction of long-distance transmission lines.

Contribution II examines the costs and transmission challenges and requirements to supply major cities in China and the United States with reliable electricity from concentrating solar power plants. This research combines quantitative power systems modeling with geographical information systems. The findings suggest that deployment of long-distance transmission lines adds complexity for the success of solar expansion–being more difficult in the United States than in China–because of their different decision-making processes for transmission line deployment. If barriers associated to the deployment of long-distance transmission lines are removed, then the findings show that concentrating solar power with thermal storage can help to integrate intermittent renewables in China and the United States, supplying not only baseload power but also power on demand, yet at very different, and sometimes very high, electricity costs for consumers. In China, the cost of supplying solar power to consumption centers on the East Coast is reasonable if the plants are in Tibet, which has excellent solar resources. The electricity cost further increases when using solar resources outside the Tibetan borders. This option may be more feasible if project developers want to avoid potential political tensions between Tibetan and Chinese authorities. The cost of supplying fully dispatchable electricity to centers of demand in the United States is not economically feasible, yet it becomes more affordable if reliability constraints decrease to similar levels as those of fossil fuel power plants.

Cooperation between the United States and China was essential for the creation of the Paris Agreement, which was crucial for developing countries to receive assistance to increase renewable energy capacity. Specifically, the Paris Agreement acknowledges the need to make carbon-neutral electricity affordable in developing countries, and mandates developed countries to provide financial resources, and calls for developing countries to improve their cooperation capacity and technology transfer. Sub-Saharan Africa (SSA) needs additional affordable, reliable electricity to fuel its socioeconomic development, and ideally, this new supply would be carbon-neutral. Concentrating solar power equipped with thermal storage can supply controllable electricity to help stabilize the continent's weak electricity grids.

Contribution III examines whether policy instruments to address political, economic, and technical challenges encountered in sub-Saharan countries can help make controllable concentrating solar power affordable. This research combines quantitative solar plant modeling and geographical information systems with insights from political science and the three mandates of the Paris Agreement. The findings show that, by implementing dedicated policy instruments to enhance cooperation capacity among sub-Saharan countries, de-risk financing costs, and improve technology transfer, controllable concentrating solar power could become an economically attractive electricity option for SSA countries. The findings also show that technological improvements alone will not suffice to make concentrating solar power competitive with coal power in SSA anytime soon, except for Southern Africa. Instead, the most important aspect of making concentrating solar power an economically attractive option in SSA countries is finance: policies to de-risk financing costs to levels found in industrialized countries are an effective way to make concentrating solar power competitive with coal power in every country. The findings imply that the most effective measure to support concentrating solar power in SSA countries is providing low-risk finance through dedicated de-risking policies, for instance, in the form of long-term power purchase agreements and concessional loans. Finally, the results suggest that success on providing low-risk finance might also benefit industrialized countries: over $10 billion could be saved annually–equivalent to about one-fourth of the official development aid for sub-Saharan countries–just by reducing financing cost of concentrating solar power investments to levels found in industrialized countries and increasing solar power supply to the power consumption level foreseen for SSA.

Zusammenfassung

Aktuelle Zusagen unter dem Pariser Klimaschutzabkommen sind nicht ausreichend, um die globale Erwärmung unter 1.5°C zu halten (IPCC, 2018). Der Zwischenstaatliche Ausschuss für Klimafragen hebt hervor, dass beispiellose Veränderungen in unseren Energiesystemen vorzunehmen sind um die Klima-Zielsetzungen einzuhalten. Dies inkludiert die Reduktion unserer Kohlendioxidemissionen um beinahe die Hälfte und die drastische Expansion von erneuerbaren Energieformen (IPCC, 2018). "Die nächsten paar Jahre sind wahrscheinlich die wichtigsten in der Menschheitsgeschichte," warnte Debra Roberts, die Vorsitzende der IPCC Arbeitsgruppe II (IPCC, 2018). Darüber hinaus weisen WissenschaftlerInnen darauf hin, dass bestehende und geplante Massnahmen für erneuerbare Energie nicht ausreichend sind um den Temperatur-Zielwert einzuhalten und dass notwendig ist, mindestens die sechsfache Kapazität erneuerbarer Energie als in bestehenden Plänen dargelegt wird, bereitzustellen (IPCC, 2018; IRENA, 2018a). In den letzten Jahren hat der Anteil an erneuerbarer Energie rasch zugenommen und dennoch ist eine schnellere Expansion nötig, um eine Energiewende herbeizuführen, die Klima-Zielsetzungen einhält. Gleichzeitig gilt es entwicklungs- und umweltpolitische Zielsetzungen zu berücksichtigen, wie zum Beispiel die Sicherstellung erforderlicher Energie für alle, die Verbesserung der Energiesicherheit, als auch die Verbesserung der Luftqualität für uns alle.

Sonnenenergie birgt ein enormes ungenutztes Potenzial und erlebt eine schnellere Ausbreitung als je zuvor: im Jahr 2017 wurde weltweit mehr Sonnenenergie-Kapazität installiert als vergleichsweise Kohle-, Gas- und Atomkraftwerke zusammen. Es wurde mehr Kapital in Solarenergieprojekte investiert als in jede andere Energiequelle–ungefähr $161 Milliarden (UNEP, 2018). Weltweit werden mehr Solaranlagen gebaut, weil sie wirtschaftlich rentabel werden. In den letzten zehn Jahren sind die Kosten für Elektrizität aus Solarenergie schneller als je zuvor gesunken und in manchen Ländern liegen verhandelte Energieankaufsraten für Solarphotovoltaik-Verträge zwischen Energieerzeuger und Abnehmer unter $0,03 pro kWh, was Solarenergie in Ländern mit alten sowohl als neuen Kohlenkraftwerken wettbewerbsfähig macht (Bailey, 2018). Trotz dieser positiven Entwicklung repräsentiert Solarenergie weltweit nur 1% der Elektrizitätssysteme, was auf unzureichende Bereitstellung von Energiespeichersystemen, Netzinfrastruktur und staatlicher Unterstützung zurückzuführen ist (Mathiesen, 2016). Falls nun Entscheidungsträger Interesse daran finden, die Temperatur-Zielsetzungen einzuhalten, wären sie gut beraten sich über Szenarien zu informieren, die Strategien zur schnelleren Implementierung von Solarenergie bieten und deren Einbindung in bestehende globale Energiesysteme erleichtern.

In Anbetracht des Ausmasses eines globalen Energiewandels und der Dringlichkeit einer Umsetzung, können Szenarien einer ausgedehnten und beschleunigten Bereitstellung von Solarenergie, die zu hochgesteckt erscheinen mögen, für Entscheidungsträger eine wertvolle Hilfestellung bieten. Daher untersuche ich im Rahmen dieser Doktorarbeit eine Reihe wissenschaftlicher Fragestellungen, die im methodologischen Ansatz alle auf hochauflösenden Modellen beruhen und sich darauf konzentrieren,

die Investitionsrate in Solarenergie zu steigern indem bestimmte Hürden und Barrieren für Solarenergie ausgeräumt werden.

In dieser Arbeit gehe ich mit drei verschiedenen wissenschaftlichen Fragen auf diese Herausforderungen ein: China ist weltführend in der Umsetzung photovoltaischer Kapazitäten und dennoch sieht sich das Land mit schlimmen und regelmässig wiederkehrenden Episoden von Luftverschmutzung konfrontiert. Daher stellt sich die Frage, wieviel Chinas Solarenergieproduktion zunehmen kann in einem Umfeld von Massnahmen zur Eliminierung von Luftverschmutzung? Falls China verstärkt variable solarphotovoltaische Kapazitäten installiert, was wäre erforderlich um steuerbare Solarenergie in Wüstenregionen zu erzeugen und an entfernte Elektrizitätsnetze zu verteilen, wo der grösste Anteil der Bevölkerung lebt? Ferner, was wären die Kosten und Übertragungsbedingungen, um steuerbare Solarenergie an die Verbrauchszentren des zweitgrössten Elektrizitätsverbrauchers und Kohlenstoffemittenten nach China, die USA, zu liefern? Wenn Temperaturvorgaben eingehalten werden müssen, um die globale Erwärmung einzuschränken, dann wird die weitgehende Umsetzung von eher erschwinglichen aber variablen Solarphotovoltaiksystemen wahrscheinlich auch in Entwicklungsländern geschehen, was mit zusätzlichen Herausforderungen verbunden ist, verglichen mit Industrieländern. Damit drängt sich die Frage auf, wie die gegenwärtige politische, institutionelle und ökonomische Situation in Ländern des afrikanischen Kontinents Einfluss nimmt auf die Wettbewerbsfähigkeit steuerbarer Solarenergie, die den Konsumzentren des afrikanischen Sub-Sahara Gebietes zur Verfügung gestellt wird?

Die drei Forschungsbeiträge, die in dieser Arbeit vorgestellt werden, zeigen für Entscheidungsträger Massnahmenszenarien auf, um die spezifischen Herausforderungen der Solarenergie anzugehen und die Vorteile, die sich aus diesen Massnahmen ergeben zu beleuchten. Im Folgenden fasse ich die Ergebnisse der Forschungsbeiträge zusammen:

China übernimmt die Führungsrolle in Bezug auf die Ausweitung von Solarkapazitäten, motiviert nicht nur von Klimawandelbedenken, sondern auch von Bedenken über Luftverschmutzung und den Auswirkungen auf die Gesundheit der Bevölkerung. *Beitrag I* untersucht die Frage zu welchem Grad Umweltbedingungen wie Luftverschmutzung der unmittelbaren Umgebung die Elektrizitätsgewinnung mittels Photovoltaik-Kraftwerken in China beeinflusst wird und damit den Profit der Solarinvestoren beeinträchtigt. Ich untersuche, in welchem Ausmass Kontrollmassnahmen zur Einschränkung von Luftverschmutzung im Fossilenergiebereich, nämlich Energie, industrieller Sektor, Transport, sowie Privat- und Wirtschaftssektoren, eine Zunahme der solaren Einstrahlung auf die Oberfläche bewirken und konsequenterweise der Elektrizitätsgewinnung basierend auf der bestehenden Generation von Solarphotovoltaikwerken. Ich stelle konkrete, sektorspezifische Kontrollmassnahmen zur Eindämmung der Luftverschmutzung vor, quantifiziere die Kosten der Umsetzung dieser Strategien und vergleiche diese mit zunehmenden Profiten für Solarinvestoren. Die Studie vereint globale Aerosol-Klimamodelle und Solarphotovoltaiksystem-Modelle mit aktuellen Markteinsichten, eingeschlossen Projektfinanzierung, finanzielle Anreize für die Solarphotovoltaikproduktion und eine Reihe präsumtiver Technologieentwicklungen im Solarphotovoltaikbereich. Die Ergebnisse zeigen auf, in welchem Ausmass die Zunahme der Solarenergieproduktion auf Emissionsreduktionen aus dem Fossilenergiebereich zurückzuführen ist und inwieweit Profite der Solarinvestoren für die Kosten der Kontrollmassnahmen zur Eindämmung der Luftverschmutzung kompensieren. Die Einnahmenzuwächse aus der gesteigerten Solarenergieproduktion könnten 2040 ungefähr 14–18% der Kosten zur Umsetzung der Massnahmen zur Eliminierung von Emissionen im Energiesektor wettmachen. Daher deuten diese Ergebnisse an, dass die Implementierung von Massnahmen zur Eliminierung von Emissionen ein ökonomisch überzeugendes Argument zur schnelleren Verbesserung der Luftqualität darstellen könnte, wenn dieselben Akteure im Energiesektor sowohl Kohlekraftwerke als auch Solarphotovoltaikwerke besitzen.

China und die Vereinigten Staaten sind die weltgrössten Energieverbraucher und die grössten Treibhausgasemittenten und somit haben deren energiepolitische Entscheidungen grossen Einfluss auf die Möglichkeiten der Welt, den Klimawandel einzudämmen. Sollten Fossilenergieressourcen mit Kohlenstoff-neutralen Energiequellen ersetzt werden, darunter variable erneuerbare Energie, dann könnte der Einsatz von grossen Mengen erneuerbarer steuerbarer Energie und potenziell Grundlastenergie–stabiler Ausstoss über das gesamte Jahr–besonders wertvoll sein. Konzentrierte Solarkraft mit thermischen Speichern kann untertags Hitze speichern und in Elektrizität umwandeln, wenn es am meisten gebraucht wird. Konzentrierte Solarkraft ist am besten geeignet für Wüstenregionen mit hoher Einstrahlung, jedoch sind diese Regionen gewöhnlich weit entfernt von verbrauchsintensiven Ballungsräumen, was Übertragungsleitungen über grosse Strecken voraussetzt.

Beitrag II untersucht die Frage der Kosten und Übertragungsanforderungen um Grossstädte in China und den Vereinigten Staaten mit zuverlässiger Elektrizität aus konzentrierten Solarkraftwerken zu versorgen. Die Studie vereint quantitative Energiesystemmodellierung mit geografischen Informationssystemen. Die Ergebnisse zeigen, dass der Einsatz von Übertragungsleitungen über grosse Strecken eine erfolgreiche Solarexpansion kompliziert–wobei dies in den Vereinigten Staaten schwieriger ist als in China–aufgrund unterschiedlicher Entscheidungsprozesse im Zusammenhang mit dem Einsatz von Übertragungsleitungen. Werden Hürden im Zusammenhang mit dem Einsatz von Übertragungsleitungen eliminiert, so zeigt die Studie, kann konzentrierte Solarkraft mit thermischen Speichern zur Integration von periodisch erneuerbaren Energieträgern in China und den Vereinigten Staaten beitragen, indem nicht nur die Grundlastversorgung gesichert wird, sondern auch Energie auf Abruf zur Deckung der Elektrizitätsnachfrage zu allen Zeiten, allerdings zu sehr unterschiedlichen und manchmal sehr hohen Elektrizitätskosten für den Verbraucher. In China ist die Belieferung von Verbrauchszentren an der Ostküste mit Solarenergie sinnvoll, wenn sich die Werke in Tibet befinden, aufgrund ausgezeichneter Solarressourcen. Der Elektrizitätspreis steigt an, wenn Solarressourcen ausserhalb der Grenzen von Tibet gespeist werden. Diese Lösung mag allerdings leichter umsetzbar sein, falls Projektentwickler potenzielle politische Spannungen zwischen Tibet und China vermeiden wollen. Die Lieferkosten an Ballungszentren mit hoher Nachfrage in den Vereinigten Staaten sind aus ökonomischer Sicht nicht tragbar, allerdings wäre eine positive Entwicklung denkbar, sollte die Zuverlässigkeit sich an vergleichbare Werte für Fossilenergie-Kraftwerke anpassen.

Zusammenarbeit zwischen den Vereinigten Staaten und China war wesentlich für das Zustandekommen des Pariser Abkommens, was entscheidend war für Entwicklungsländer, um Beihilfen für die Entwicklung von erneuerbaren Energieträgern zu erhalten. Das Pariser Abkommen erkennt die Notwendigkeit, Kohlenstoff-neutrale Elektrizität in Entwicklungsländern erschwinglich zu machen. Zu diesem Zweck werden Industrienationen verpflichtet finanzielle Ressourcen bereitzustellen und Technologietransfer zu vertiefen, dies neben dem Aufruf an Staaten, deren Kooperationspotenzial zu vertiefen. Sub-Sahara Afrika (SSA) benötigt zusätzlich preiswerte und zuverlässige Elektrizität um die soziale und ökonomische Entwicklung des Landes voranzutreiben und idealerweise wäre diese Zufuhr Kohlenstoff-neutral. Konzentrierte Solarkraft mit thermischen Speichern kann steuerbare Elektrizität liefern und dazu beitragen, die schwachen Stromnetze des Kontinents zu stabilisieren.

Beitrag III untersucht die Frage ob politische Instrumente zur Thematisierung von politischen, ökonomischen und technischen Herausforderungen in Ländern des Sub-Sahara Bereiches hilfreich sein können, um steuerbare konzentrierte Solarenergie wettbewerbsfähig zu machen. Die Studie vereint quantitative Solarwerkmodellierung und geografische Informationssysteme mit Erkenntnissen aus den Politikwissenschaften und den drei Mandaten des Pariser Abkommens. Die Ergebnisse zeigen, dass mit der Implementierung zugeordneter politischer Instrumente mit dem Ziel der Vertiefung multinationaler Zusammenarbeit unter den Sub-Sahara Ländern, der Eliminierung von Risikofinanzierung von Kosten und der Verbesserung von Technologietransfer, steuerbare konzentrierte Solarenergie zu einer ökonomisch attraktiven Alternative für SSA Länder werden könnte. Die Ergebnisse zeigen auch, dass technologische Verbesserungen allein nicht ausreichend sein werden, um in SSA Ländern konzentrierte Solarenergie im Vergleich zu Kohleenergie in absehbarer Zeit wettbewerbsfähig zu machen, davon ausgenommen das südliche Afrika. Hingegen ist Finanzierung der wichtigste Aspekt, um konzentrierte Solarenergie in SSA Ländern wirtschaftlich reizvoll zu machen: Massnahmen zur Eliminierung der Risikofinanzierung von Kosten und eine Angleichung an Werte wie sie in Industrieländern gesetzt werden, ist eine zielführende Strategie, um konzentrierte Solarenergie gegenüber Kohleenergie in jedem Land wettbewerbsfähig zu machen. Die Ergebnisse deuten an, dass die effektivste Massnahme zur Unterstützung konzentrierter Solarenergie in SSA Ländern die Bereitstellung von risikoarmer Finanzierung durch gezielte De-Risking Finanzierungsstrukturen darstellt, wie zum Beispiel in Form von langfristigen Stromabnahmeverträgen und vergünstigten Darlehen. Schliesslich, die Ergebnisse deuten an, dass der Erfolg einer risikoarmen Finanzierung auch Industrienationen zugutekommen könnte: mehr als $10 Milliarden könnten jährlich eingespart werden–was einem Viertel der öffentlichen Entwicklungshilfe für Länder der Sub-Sahara Region entspricht–lediglich durch die Reduzierung der Finanzierungskosten von Investitionen in konzentrierte Solarenergie und eine Angleichung an Werte der Industrieländer, sowie eine Steigerung von Solarenergie auf das für SSA vorhergesehene Energieverbrauchsniveau.

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CHAPTER 1. Introduction

1.1. Motivation and general background

The Intergovernmental Panel on Climate Change (IPCC) emphasizes that limiting global warming to 1.5°C requires fast, far-reaching and unprecedented changes in all aspects of society including land, energy, industry, buildings, transport, and cities. As Debra Roberts, chair of IPCC Working Group II emphasized "The next few years are probably the most important in our history" (IPCC, 2018). Global emissions of carbon dioxide would need to fall by almost half from 2010 levels by 2030, and reach "net zero" around 2050 (IPCC, 2018). The deep emissions cuts will need to happen fast and in all sectors.

Globally, around half of all carbon dioxide emissions are the result of electricity and heat production (IEA, 2018b). Therefore, if we aim to meet the climate target, it is crucially important to increase our understanding of how we decarbonize the electricity sector and adopt appropriate energy strategies, policy instruments, and low-carbon technologies. Policymakers can consider including in their energy strategies a range of low-carbon options that fall into three broad categories:

i) Power derived from nuclear fission is a possible solution to the climate crisis;

ii) Continued reliance on coal-fired power plants is another potential option, these plants are equipped with carbon capture and storage that traps and keeps carbon instead of releasing it into the atmosphere. These plants, however, have repeatedly suffered setbacks as countries have continually pulled their support for demonstration projects (Simon, 2018); and

iii) Countries could replace fossil fuel power with renewable sources such as solar and wind power, bioenergy, hydropower, and geothermal.

A climate-friendly electricity system might consist of a constellation of these three categories, coupled with demand-side management for consumers to encourage them to optimize their electricity use. Despite an uncertain future for electricity choices, there is reason to believe that renewable energy might be a crucial actor in an energy transition toward a zero-carbon future that ensures energy for all, improves energy security, achieves climate targets, and ameliorates the air we breathe.

The International Renewable Energy Agency (IRENA) highlights that, among all renewable energy options, solar power and wind power are poised to become the dominant power sources in future electricity systems (IRENA, 2018a). Solar power has an enormous potential globally and is the fastest-growing source of renewable energy worldwide, accounting for up to two-thirds of new power capacity (IRENA, 2018a). Government policies and falling costs are the main reasons for solar power expansion. Over the past five years, the average cost of solar photovoltaics power has declined 65%, while the average cost of onshore wind power has declined 15% (IEA, 2018a). In some places like Mexico, Saudi Arabia, and Chile, new power purchase agreements for solar photovoltaics fall below 3 cents per kWh

(Bailey, 2018). That price puts solar at or below the cost of a new natural-gas plant or coal power plant (EIA, 2018a). Indeed, solar photovoltaics power is becoming well-placed to outcompete the costs of fossil power globally.

However, the power output from solar plants varies fast as the cloud cover comes and goes, posing significant challenges for the reliability of the electricity grid. The International Energy Agency (IEA) states that electricity systems worldwide are "experiencing its most dramatic transformation since its creation more than a century ago" (IEA, 2018a), as countries are adapting to integrate variable power in the grid. Ensuring an economic, reliable, and climate-friendly electricity system would require strengthening existing equipment, modifying regulations, developing low-cost power storage to respond quickly to changes in demand, and expanding transmission and distribution grids (IEA, 2018a). The power output from solar plants may also be affected by ambient conditions such as air pollution from burning fossil fuels in several economic sectors, reducing solar irradiation that reaches the ground.

Given the unprecedented changes needed in the electricity sector and the urgency of making them a reality, policymakers may find valuable scenarios examining large-scale deployment of solar power. However, deploying solar power at a pace and scale never encountered before hinges on a number of barriers and challenges that may hinder the expansion of solar power in those countries that decide to advance solar power to help meet climate change objectives, but also in those that commit to advance solar power to meet other social and environmental objectives. Therefore, it is crucially important to increase our understanding of policy decisions that might help overcome these barriers–being these technical, economic, political, and environmental–and the effect of removing these barriers in specific countries' contexts, for countries with different developmental conditions.

1.2. Structure of the thesis

This accumulative doctoral thesis is built on three scientific research papers examining policies seeking an increase in solar power in countries with different developmental contexts and, at the same time, policies seeking to overcome barriers and challenges that may hinder a faster expansion of solar power. This thesis is structured as follows:

- In chapter 1, in section 1.3, I introduce the interactions between climate, social, and environmental goals.
- In section 1.4, I introduce the drivers for renewable energy deployment.
- In section 1.5, I introduce the challenges and barriers for renewable energy deployment.
- In section 1.6, I introduce the challenges and barriers for solar power deployment.
- In section 1.7, I introduce the research objective and research questions.
- In section 1.8, 1.9, 1.10, I summarize the findings from *contributions I, II,* and *III.*
- In chapters 2, 3, and 4, I introduce the science that might support the policy making throughout *contributions I, II,* and *III* in manuscript form, with supplementary information included as appendices.
- Last, in chapter 5, I introduce the broader implications of the findings for policy making.

1.3. Interactions between climate, social, and environmental goals

Climate policy to limit global warming has important linkages with social and environmental objectives such as air quality and clean water and by extension human health, and reliable and affordable energy. Moreover, it is primarily important to understand these linkages, as a reduction of carbon-emitting sources of energy to address climate change, for example, can lead to important air quality and health co-benefits; yet when these sources are substituted by renewable energy, their power output can affect the reliability of electricity systems and the electricity price paid by consumers.

Addressing climate change and air pollution is becoming a dual political priority for an increasing number of countries worldwide (EC, 2018; State Council, 2018) and might be for many more as climate change is poised to worsen the quality of the air. The so-called Chinese *airpocalyspe*, for example, was not the result of emissions alone, but of acute stagnant atmospheric conditions that worsened the smog. During winter 2013, the air over the Chinese plains was still and locked in the smog; the slowing of vertical circulation prevented particulate matter from moving up to the higher atmosphere, and as in almost every winter, there was a lack of rain, preventing pollutants from washing out. That smog episode was one of the many episodes that followed. If air pollution is a political problem today, one can only imagine how dire the situation might get if climate change intensifies it. Air pollution affects not only public health but the economy too, as it may be costing the Chinese economy about $38 billion per year as a result of premature deaths and the loss of food production (Kao, 2018), while in Africa it causes more premature deaths than unsafe water or childhood malnutrition (Roy, 2016).

Policies to address climate change may also affect the affordability of the electricity to consumers. The cost of the electricity from renewable energy technologies has been decreasing during the last decades and in some regions is now the least-cost power supply option (EIA, 2018a); however, in many other regions, particularly in the global South, the electricity from some renewable energy technologies is not yet affordable (EIA, 2018a). The decarbonization of the electricity systems could result in price shocks if the cost to transition to a low-carbon economy is too high, preventing an improvement of the standard of living for the world's poorest. Moreover, ensuring the world's most underprivileged have access to affordable, reliable and modern energy services would enable poverty eradication. If innovations on renewable energy technologies continue and risk perception and finance improve, among others, a broader range of renewable energy technologies would become affordable in a greater number of developing regions, helping reduce poverty while increasing the health and well-being of the citizens.

1.4. Drivers for the deployment of renewable energy

Climate change mitigation has been the primary rationale to transition to a renewables-based future, yet it is not the only driver to advance renewable energy deployment.

1.4.1. Public health

In many countries, reducing air pollution and associated health problems is a driver for the deployment of renewables. As mentioned, Chinese citizens have been suffering from acute health problems resulting from air pollution mainly from fossil-fuel-based sources, largely coal-fired plants. As a result, the Government announced that China aims to consume 20% of its primary energy from non-fossil sources by 2030 (Su, 2015), for which investments in renewables are crucial.

1.4.2. Affordability of power

Cost of some renewable technologies is decreasing rapidly and, in many countries, renewables are now cost-competitive with new fossil fuel and nuclear sources (EIA, 2018a)–even more so when considering subsidies to non-renewable sources. There are three main drivers for cost reductions in renewable energy technologies, particularly solar and wind power: ii) competitive procurement, iii) a large and growing base of experienced and internationally active project developers, iii) and technology improvements such as innovations in solar photovoltaics manufacturing and installations, improvement in wind turbine materials and designs, and advances in thermal energy storage for concentrating solar power (IRENA, 2018c). For example, bidding procurement processes for electricity like auctions are driving renewable energy investments while reducing technology costs and making the electricity more affordable. Between 2010 and 2016, the electricity price from solar photovoltaics from auctions has become five times cheaper, while the electricity price from onshore wind reduced almost by half (IRENA, 2018c).

1.4.3. Socio-economic benefits

Socio-economic benefits are gaining prominence as an important driver for renewable energy deployment. Investments in renewable energy increase local income, enhance trade balances, strengthen industrial development, and create jobs. IRENA (2016) shows that doubling the share of renewable energy may create 24 million jobs from direct and indirect employment worldwide by 2030, i.e. employment directly linked to the renewable energy sector and employment from supporting industries such as software or steel; while it may also increase global social welfare and improve human well-being by 3.7% compared to an increase in global gross domestic product (GDP) of 1.1%. Welfare captures consumption and investment in productive capital, human capital improvements through education and health, and the depletion of natural resources, which go beyond the merely economic aspects captured by GDP.

1.4.4. Energy security

Energy security to increase energy system resilience in the face of anticipated climate change impacts may also be a driver for renewable energy development. The definition of energy security is context-dependent, depending on country, region, timeframe or energy source to which it is applied, mainly fossil fuel sources such as oil and gas (IEA, 2019). Because of the distributed nature of renewable energy resources, they might help decrease energy import dependence from third-countries, reduce power supply disruptions, and limit excessive price volatility (IEA, 2019). Moreover, renewable energy resources are unlimited–depending on country and energy source–compared to the exhaustible fossil-fuel resources. Hence, energy security might be a driver for renewable energy acting as a substitute of fossil-fuel power and improving the security of supply.

1.5. Challenges and barriers for renewable energy deployment

The above-mentioned drivers are advancing renewable energy deployment, yet progress has not been equal across countries and technologies, and also it may not be happening fast enough if the temperature target is to be met on time. The reason for progress being insufficient is the many barriers and challenges on renewable energy deployment; some of them introduced below:

1.5.1. Policy and regulatory barriers

Policies and regulations that create a stable and predictable investment environment are essential to increase the interest of renewable energy technologies to investors, and therefore a lack of it can hinder the adoption of renewable energy technologies (IRENA, 2018c). For example, regulatory measures such as standards and codes can minimize technological and regulatory risks associated to renewable energy investments. Because large-scale renewable energy projects require vast amounts of capital, a lack of well-defined policies to attract private investors can also hinder renewable energy deployment.

As renewable energy deployment moves forward, policy makers are confronted with other challenges, some of them associated with the variable nature of the renewables and its integration into power grids.

1.5.2. Technical barriers

Technical barriers to renewable energy deployment stem from the inadequate technology and lack of infrastructure required to support the continuous increase of variable renewables in power systems. The power output from solar plants and wind farms changes rapidly depending on weather conditions, posing significant challenges for the reliability of electricity grids. For example, the IEA suggests that variable generation such as wind and solar photovoltaics combined may represent more than 80% of global renewable capacity growth over the next five years, increasing the need for power systems to adapt rapidly to upcoming increasing levels of variable power generation (IEA, 2017a).

One of the most important structural barriers is the lack of transmission and distribution networks to connect renewables to the grid. This barrier is particularly visible in developing countries and it worsens if high-quality renewable resources are far away. Moreover, developing countries may face a lack of proper transmission and distribution equipment that needs to be imported from abroad (IRENA, 2015a). This reliance on industrial countries for imported equipment applies also to servicing and maintenance, as developing countries may face a lack of spare parts and a lack of trained labor to perform the maintenance, thereby decreasing the reliance on specific renewable energy technologies.

1.5.3. Financial and economic barriers

One of the main barriers that hinders the adoption of renewable energy technologies in some markets is their higher generation costs compared to those from fossil-fuel based technologies. For this reason, in some countries, people are more likely to consume electricity from coal plants or from diesel-based generators simply because the electricity might be more affordable. Because renewable energy technologies have high upfront investment costs but low operation costs compared to fossil alternatives as they have no fuel costs (except for biomass power), both investment costs and financing costs (cost of capital) are important drivers of electricity generation cost from renewables. Additionally, many project developers prefer to keep initial investment costs low while maximizing profits; therefore, as investment costs of renewable energy technologies per installed capacity may be higher than that of non-renewables, they may become a barrier for investments in clean energy. Investment costs for renewable technologies are also commonly higher in developing than in developed countries because of an absence of local manufacturing capacity, poorly trained labor forces, the need to bring in technologies, equipment, and engineers from abroad or industrialized countries, and/or the absence of an adequate logistics infrastructure, such as well-developed highways or railways (IRENA, 2015a).

Developing countries face higher financing costs compared to developed countries too, as they characterize the extra reward required by investors and lenders to compensate them for risks, which are usually higher in developing countries. These risks arise from perceived or factual political, regulatory, financial, and administrative barriers, lengthy and uncertain permission processes, and other general investment risks (Ondraczek *et al.*, 2015; UNDP, 2013). These risks translate into inadequate or lack of credit to invest in renewable energy projects or simply into being the interest rates on credit too high. Because of these risks, few financial institutions (both public and private) are willing to extend sizable loans to develop renewable energy projects.

1.5.4. Market-related barriers

Renewable energy technologies face unfair market competition, compared to fossil fuel technologies, as in many countries the latter still receives subsidies, making renewable energy comparably more expensive (IRENA, 2018c). Other market-related barriers are: subsidies to nuclear power, distortions in market power, lack of successful and replicable renewable energy business models to facilitate the transition of small-scale projects into commercial business, lack or market for renewable energy, and trade barriers for importing renewable energy products (IRENA, 2018c).

1.5.5. Awareness and capacity barriers

Socio-cultural barriers such as household's unwillingness to transition to renewable energy for fear of the supply being unreliable and because of lack of general awareness of the technologies, are a deterrent for the adoption of renewable energy technologies in some countries, particularly in the global South. Additionally, people may be unwilling to adopt certain renewable energy technologies because they may face a lack of trained labor to educate, demonstrate, maintain and operate these technologies and associated infrastructure, and they may decide not adopt it because of fear of failure (IRENA, 2018c).

1.5.6. Public acceptance and environmental barriers

Insufficient progress on renewable energy deployment may also be the result of incompatibility of climate objectives with public acceptance or availability of natural resources. For example, concentrating solar power technologies require high direct solar irradiance to function and some also require large amounts of water to cool down the system (Bracken *et al.*, 2015). This may be a problem, since regions with high levels of solar irradiance may also be water scarce, conflicting with sustainability objectives such as the use of water for agriculture. Local planning and environmental features may also conflict with societal preferences for the location of wind farms; citizens whose values align with climate objectives and environmental protection and therefore in favor of wind power, may oppose to the construction of wind farms within their visual and/or audible range (IRENA, 2018c).

1.6. Challenges and barriers for solar power deployment

Removing specific challenges and barriers on solar power can be helpful for countries aiming to increase its deployment. Among the many challenges to increasing solar power in power systems, this thesis investigates four in particular, arising from: i) environmental conditions, such as air pollution; ii) increasing the share of intermittent solar resources, which affect the reliability of electricity systems, requiring the adoption of flexible, controllable and carbon-neutral sources of power; iii) increasing system interconnection, as the highest-quality solar resources may be far away from high-consumption centers, requiring the deployment of long-distance transmission; and iv) solar power might still not be an affordable option in many countries, mainly developing countries.

1.6.1. Air pollution

Satellite-derived data suggests that surface solar radiation decreases because of ambient air pollution, as atmospheric aerosols attenuate solar radiation by scattering and absorbing sunlight (Li *et al.*, 2017). A reduction of solar radiation reaching the solar panel leads to a reduction in the generation of solar photovoltaics. This effect may be particularly important to understand in countries with high levels of outdoor air pollution that plan to increase the shares of solar power in their electricity systems, including India, China, and some African countries. In Africa, for instance, air pollution is particularly acute in fast-developing countries such as Egypt, South Africa, Ethiopia, and Nigeria (Roy, 2016).

1.6.2. Unaffordable solar power

Globally, solar power is not yet cost-competitive with fossil energy sources. Particularly, the cost of solar power in developing countries is usually higher than in developed countries, mainly because of higher investment and financing costs for generation and transmission projects. For this reason, to increase the attractiveness of renewable energy technologies to investors, de-risking mechanisms may prove beneficial. Policy instruments that have traditionally supported the deployment of renewable energy have been public de-risking mechanisms such as feed-in policies, which provide a financial incentive per kWh supplied to the grid and which proved effective to increase the share of solar power in developed countries like Spain and Germany (REN21, 2018b). Developing countries might benefit the most from de-risking mechanisms to improve the financing costs of renewable energy and transmission projects, increasing the affordability of electricity from such projects.

Despite financing costs being an important determinant for the success of renewable energy projects, few studies have actually considered country-specific financing risks when estimating the cost of electricity from renewables (Frisari and Stadelmann, 2015; Ondraczek *et al.*, 2015; Schinko and

Komendantova, 2016; Shrimali *et al.*, 2013; UNDP, 2013). Most studies assume uniform (standardized) financing costs for all countries within a study. Among them are studies carried out by IRENA that use a uniform financing cost of 10% in all the countries of the world, including in each African country, except OECD countries and China, where it used a uniformly lower financing cost. There, borrowing costs are moderately low and have stable regulatory and economic policies (IRENA, 2015b, 2017, 2018b). The selection of the financing cost is important, as it can influence investor's decisions to invest in one project or another. For instance, reducing the financing costs of a concentrating solar power project from 10% to 5%, reduces the levelized cost of electricity about 30% to 25% (IRENA, 2012a; Yang *et al.*, 2018). The use of a uniform financing cost facilitates a comparison between projects and technologies across countries worldwide, but it also means that the risk profile of all countries is assumed to be the same, which is incorrect. One way to reduce the risk profile is via international financial institutions through North–South cooperation, which can enable attractive policy environments for renewable projects by combining financing, risk mitigation, and technical assistance. For instance, the World Bank manages the Middle East and North Africa (MENA) Concentrating Solar Power Investment Plan, which aims to mobilize $5 billion in public and private financing. These funds were partially used to finance the 500 MW Noor complex in Morocco (World Bank, 2017). Additionally, IRENA (2015a) suggests that efforts to benchmark local methods in African countries to global best practices might prove useful to reduce the investment cost of solar power projects.

1.6.3. Unreliable operation of power systems

Several technological options exist to increase the reliability of power systems including, demand-side response, battery storage or thermal storage such as concentrating solar power plants equipped with thermal storage capable of dispatching power on demand to smooth out power fluctuations. Other options to supply power on demand are biomass and hydropower, yet sustainability concerns and a lack of potential for new-build plants might constrain the possibilities for their expansion.

Concentrating solar power receives heat from the sun, and if equipped with thermal storage, it can generate electricity on demand after sundown and during cloudy days. This unique characteristic makes this renewable technology one of the few that can generate dispatchable or even baseload power at a constant output throughout the year on a large scale (Pfenninger *et al.*, 2014b). Despite this technical advantage, the global installed capacity of concentrating solar power plants is limited compared to that of other renewables. Its expansion started in the eighties, yet deployment has only taken place in a few countries such as the United States, Spain, Morocco, South Africa, China, the United Arab Emirates, and India (Lilliestam *et al.*, 2017). The global installed capacity is currently about 5 GW, or less than 1% of the combined capacity of variable wind power and solar photovoltaics (REN21, 2018a). Some of the reasons are that their levelized electricity costs are high compared with the electricity costs from coal, gas, and oil (Lilliestam *et al.*, 2017). In addition, the plant must be constructed on flat land in areas of high direct solar irradiance, preferably close to transmission lines and a water supply if a wet cooling system is used. Otherwise, a dry cooling system must be used at a higher cost (Bracken *et al.*, 2015). Moreover, investors perceive the risks of this technology as relatively high (CIF, 2015).

Solar photovoltaics systems operate at any level of solar irradiation, yet concentrating solar power plants operate only under high levels of direct solar irradiance typically found in desert and arid regions. Usually, these regions are far from high-consumption centers. The highest but most distant solar resources may be the most economical, if the quality of the resource and no other factors like financing costs are considered. To benefit from these high-quality but distant solar resources, however, it might be necessary to deploy long-distance transmission lines.

1.6.4. Far-away high-quality solar resources

To connect faraway high-quality renewable resources with consumption centers where power is needed the most, possibly the best techno-economic solution is to deploy long-distance high-voltage direct current (HVDC) transmission lines, because its economics are better than alternating current (AC) lines for distances over 600–800 km and the electricity losses are lower than for AC lines (IEA, 2016). Examples of long-distance transmission include transmitting distant wind and hydropower in Western China and hydropower in Africa (IEA, 2016). The longest transmission line will be the Chinese Changji-Guquan line, which will transmit power from the Xinjiang region in the northwest to Anhui province in the East, more than 3,000 km away (ABB, 2018).

The success of deploying long-distance transmission lines hinges on the borders that the line must cross and on the cooperation capacity between administrations. The deployment of transmission lines along diverse countries, provinces, and states is likely to face more challenges compared to lines crossing regions under the same administration. For instance, the State Grid Corporation of China deployed, just in three years, a 1,980-km-long transmission line (State Grid, 2010), which is the same distance as if power was brought from sunny Los Angeles in California north to cloudy Seattle. Instead, the success of realizing long-distance transmission projects in the United States hinges on a patchwork of federal, state, county, and city jurisdictions. There is no federal agency with authority over the transmission infrastructure, and for this reason, it can take years to secure permits for projects. For instance, the last long-distance HVDC line to be built that will bring power from Oklahoma to Tennessee was proposed in 2009. It won approval seven years later, and construction is expected to end in 2020 (Roberts, 2016).

The provision of long-distance transmission might be even more difficult in developing countries. The deployment of such projects in Africa revolves around South–South cooperation within its power pools, which are specialized agencies that leverage cross-country cooperation to pool power through countries to benefit from lower electricity costs and improve the reliability of their power systems. However, cooperation between African countries has proved many times insufficient to build such long-distance transmission projects. The Inga 3 dam project in the Democratic Republic of the Congo (DRC), exemplifies a long-distance transmission project that seemed economically attractive. That is, the World Bank estimated the full expansion of regional power trade from the DRC to South Africa could save the region $1.1 billion annually in power costs (World Bank, 2014b). However, the project exists only on paper because of numerous obstacles since the early 1950s and insufficient institutional cooperation on the part of the countries involved (International Rivers, 2016).

1.7. Research objective and research questions

To advance the deployment of solar power globally, it is important to inform policymakers with scientific information that may contribute to overcome the challenges and barriers described in section 0. Therefore, the overarching research objective of this work is to determine how specific challenges and barriers for solar power deployment can be removed, and what are the benefits of addressing these challenges for a country that decides to expand solar power.

In this thesis, I investigate policies seeking to increase solar power generation and policies seeking to deploy controllable solar power while increasing its affordability for consumers. The countries analyzed in this thesis have different economic, political, policy, and developmental conditions, and different social and environmental objectives, namely China, the United States, and sub-Saharan countries. The solar technologies examined here have diverse maturity stages, markets developments, and value for the grid: solar photovoltaics and concentrating solar power equipped with thermal storage.

To make the overall research objective operational, I compartmentalize this study into three connected but distinct research questions that comprise the three scientific research contributions:

The **first research question**, which I answer in *Contribution I*, deals with increasing solar power generation without installing a single extra megawatt of solar capacity, just by reducing air pollution:

- China is the world leader in deploying solar photovoltaics capacity. How much can the country's solar power generation increase with policies seeking to mitigate the country's air pollution?

The **second research question**, which I answer in *Contribution II*, concerns increasing solar power capacity while providing controllable solar power to distant consumption centers.

- If China seeks to increase variable solar photovoltaics power and if this mostly happens where most of the population lives, on the East Coast, what are the cost and transmission requirements to supply controllable solar power to consumption centers in the East?
  In addition, what are the cost and transmission requirements to supply controllable solar power to consumption centers in the second-largest electricity consumer and carbon emitter after China, the United States?

The **third research question**, which I answer in *Contribution III*, regards increasing solar power capacity in the power systems of Africa–which is facing more challenging technical, economic, and political conditions than developed or emerging countries–while providing more affordable controllable solar power to distant consumption centers.

- If the temperature target to limit global warming is to be met, then affordable but variable power is likely to increase in developing and least developed countries. These countries face challenges that differ from those found in developed economies. Therefore, how much do policy instruments to address the political, economic, and technical challenges encountered in sub-Saharan countries matter to make controllable concentrating solar power more affordable for consumers?

Table 1 below introduces the framework that summarizes the barriers and challenges for the expansion of solar power as well as the policy decisions that are examined in the three scientific contributions.

Table 1 Barriers and challenges influencing solar power expansion and their role in the contributions of this thesis.

		Contribution		
Barrier and Challenge	**Policy decision**	**I**	**II**	**III**
Air pollution	Reduction of outdoor air pollution	x		
Unreliable power system	Deployment of concentrating solar power with thermal storage		x	x
Far-away solar resources	Deployment of long-distance transmission lines		x	x
Unaffordable power	Reduction of financing costs, increase of technology transfer, and increase of cooperation capacity			x

The pace of renewable energy deployment is not happening fast enough to achieve the temperature target, and current and planned policies to increase renewable energy are insufficient (IPCC, 2018). There are many barriers and challenges ahead of us, with every single country or region–being Europe, Africa, China or the United States– having the same but different challenges when pursuing renewable energy growth. There is reason to believe that we need more ambitious policies to scale up renewables, and that with the right policies in place, the power sector could be emissions-free by mid-century. The policies that I will discuss in this thesis will not necessarily significantly contribute to the 1.5°C target, as their implementation may be too long-term in nature and thereby their contributions might come too late for that target; yet, they may contribute to a multi-faceted policymaking system designed to also achieve energy, social, and environmental goals.

1.8. Synopsis of Contribution I: Blue skies over China: The effect of pollution-control on solar power generation and revenues

Meeting increasing electricity demand with renewable energy sources has the potential to transform not only the health of the planet, but also the health of the people. China is one of the countries with the highest levels of air pollution, and almost every major Chinese city exceeds the limits defined by the World Health Organization as reasonably safe for health (HEI, 2017; Landrigan *et al.*, 2017; Rohde and Muller, 2015; World Bank, 2016a). China also has the largest solar photovoltaics installed capacity worldwide (Bloomberg NEF, 2017) and is an undisputed leader in capacity growth driven by climate change targets and air pollution concerns for public health (IEA, 2017a). The Chinese National Renewable Energy Centre foresees that current solar photovoltaics capacity will increase up to threefold by 2030 and up to sixfold by 2040 (CNREC, 2014).

The government has implemented several policies to reduce air pollution, successfully in some, but far from all sectors. These policies resulted in similar measures as those implemented in industrialized economies, including the installation and operation of pollution-control equipment on major point sources, such as coal power plants and motor vehicles, or the locally specific replacement of coal for residential and commercial heating with natural gas or propane (Crane and Mao, 2015). These policies have been successful at reducing air pollution to some extent, yet the outcome could be much better. Coal-burning power and industrial plants can be retrofitted with state-of-the-art pollution-control equipment to reach near-zero emissions similar to or even lower than those from a natural gas combined-cycle unit. Road transport and navigation can switch to cleaner fuels with lower levels of sulfur and install stricter pollution-control equipment, and residential and commercial heating and cooking can be switched from coal to natural gas nationwide (Crane and Mao, 2015; ICCT, 2015a; World Coal Association, 2017).

If the government decides to implement such policy instruments to largely reduce or eliminate air pollution, solar power generation from the current fleet of solar photovoltaics plants would increase. Moreover, if solar power generation increases, the amount of electricity fed into the grid also increases alongside the revenues to solar investors from the feed-in tariffs (FiTs) in place. The Chinese solar industry has large untapped revenue opportunities that could be exploited if air pollution were reduced. Therefore, I calculate how much solar power generation would increase if the government implemented policies to reduce air pollution from the fossil fuel sectors, namely, energy, industrial, residential, commercial, and transport. Moreover, I calculate how much revenues to solar investors would increase by eliminating emissions from each single sector or a combination of them. Given the ministerial decision-making structure of the Chinese government, there is reason to believe that an appraisal of the costs of pollution control policies and their economic benefits lying entirely within the Chinese energy system could provide an economically salient argument for accelerating improvements in air pollution. A cost-benefit appraisal serves as an input for decision-making, as quantifying the problem's impact in this manner enables decision-makers to assess the utility of mitigation measures. Therefore, I perform an appraisal of the costs of different clean-air policies to mitigate emissions and of the benefits, that is, revenues created for the solar industry.

Summary of Contribution I's results

1. **Policy decision: Reduction of emissions from fossil fuel sectors**

   If emissions from fossil fuel sectors are reduced, solar power generation increases. If ambitious air pollution control policies were implemented in all fossil fuel sectors, the solar power generation from all grid-connected solar photovoltaics plants in China as per installed capacity in 2016 would increase about 14%. For future projected fleets, the increase in solar power generation would be 49 to 73 TWh for 2030, which is roughly the current power demand of a mid-sized European country without a single MW of additional photovoltaics installation, and 85 to 158 TWh for 2040, depending on the capacity targets foreseen by the Chinese National Renewable Energy Centre.

   The increase in solar power generation also varies depending on the sectorial policies implemented to eliminate emissions. Policies to eliminate emissions from the energy sector result in an increase in solar power generation by up to 3.5%, from the industry sector only by up to 5%, and from the residential and commercial sector only by up to 3%. Policies to eliminate emissions from several sectors simultaneously yield much stronger benefits: eliminating today's emissions from energy and industry increases solar power generation by up to 11%, while eliminating emissions originating in the residential and commercial sector also increases generation by up to 27%. The contribution of emissions from transport is small compared to those of the other sectors. Removing its emissions also increases generation only by up to 29%, representing only a slight increase.

   These findings imply that the largest effect on solar power generation will be achieved when emissions from the energy and the industrial sectors, that is, the sectors that have received the most attention on emissions reductions, are eliminated completely, in addition to emissions from the residential and commercial sectors. Once emissions from the latter are removed, solar power generation increases by more than twice as much than eliminating emissions from the energy and industrial sectors only. China has focused on reducing emissions mainly from the energy and industrial sectors. The findings show that implementing policies to bring emissions from these sectors to zero and implementing policies to bring down emissions from the residential and commercial sector as well would result in the largest incremental increase in solar power generation.

   If emissions from fossil fuel sectors are reduced, revenues to the solar industry also increase. For 2016's solar installed capacities, implementing emission control policies in all sectors would have created about $1.4 billion in additional revenue from increased solar power generation for the given FiT since each solar plant was installed. This amount equals the economic losses from the curtailment of solar power because of the grid instability experienced in that same year.

Revenue increases in the future depend on factors such as the solar capacity scenario, technological learning rates on solar photovoltaics, and discount rates, which are used to discount future revenues to the present. Implementing emission control policies in all sectors would generate substantial revenues by 2040: an average of $5 billion/year for a low-capacity scenario and an average of $7.6 billion/year for a high-capacity scenario, when considering various discount rates and technological advancements.

Revenues depend on the selection of technological learning rates and the discount rate. The examined scenarios assume, first, a technological learning rate of 20%, which is the learning seen for every doubling of installed photovoltaics capacity (Sivaram and Kann, 2016), and second, no learning at all, that is, no cost reduction overtime. Likewise, other scenarios examined assume, first, a discount rate of 5%[1]–used commonly for mitigation options in China by researchers who favor renewables, and second, a discount rate of 8%[2]–used by the government to assess government investment decisions. Results show that the difference in revenues of choosing one discount rate or another is lower than assuming the historical learning rate or no learning at all. These findings imply the progress on reducing the cost of manufacturing solar cells and panels seen in the past might outweigh the categorizing of solar power under the two common risk schemes.

Last, if emissions from fossil fuel sectors are reduced, the revenues from the increase in solar power generation offset a sizeable share of the costs of air pollution control measures. The revenue gains from the increased solar power generation by 2040 could offset up to about 13 to 17% of the costs of implementing policy measures to eliminate emissions in all sectors. However, given past progress, the energy sector could be the sector where strong pollution control could be the fastest to implement. Accordingly, revenues from implementing policy measures to eliminate emissions from the energy sector only could offset some 14 to 18% of the cost of eliminating emissions. In this case, the revenues and the costs would be entirely in the same sector: electricity generation. These findings imply that, if the same actors in the energy sector own both coal and solar photovoltaics generators, the implementation of policies to eliminate emissions might provide an economically salient argument for accelerating improvements in air pollution.

[1] Non-governmental organizations supporting renewables like the International Council on Clean Transportation assume in their study *Costs and Benefits of Motor Vehicle Emission Control Programs in China* a discount rate of 5%. Thus, this is toward the lower end and influences investor's decision toward renewables.

[2] The National Development and Reform Commission and the Ministry of Construction of China in their joint publication Economic Evaluation Methods and Parameters for Construction Projects agreed to use a discount rate of 8% for evaluating construction investment projects in China, assigning a higher risk to investments.

The cost-benefit appraisal of the cost of clean-air policies and future revenues for the solar industry depends on the size of the solar photovoltaics fleet and FiTs, which depend on the learning and discount rate. The scenarios with technological learning (or a higher discount rate) result in lower profit margins over time, compared to scenarios without learning (or a lower discount rate). The difference in profit margins for the two discount rates, for instance, is about $1.3 billion/year. These findings imply that the selection of one discount rate may not be a decisive factor to decide whether to implement the clean-air policies–if the decision followed solely an economic perspective.

1.9. Synopsis of Contribution II: Cost and transmission requirements for reliable solar electricity from deserts in China and the United States

China and the United States are the world's largest energy consumers and together account for about 40% of global greenhouse gas emissions (IEA, 2014a; WRI, 2015). If renewable sources substitute for their fossil fuel capacity, these countries might play a major role in the world's capabilities to limit climate change. If China and the United States decide to deploy large amounts of variable renewables (as seen for China in *Contribution I*), electricity system operators and regulators will need to plan for system resources that can meet constant demand and for the system to be resilient enough to withstand rapid changes in conditions. Most of the flexibility for power systems in China and the United States has been provided by transmission interconnections with neighboring systems and by flexible generation capacity, such as hydropower and natural gas power. China, however, is facing serious problems from the fast-growing variable renewables. Consequently, the inability of the grid to handle wind and solar power from the remote areas and resource-rich areas in the North and West is leading to curtailment rates for solar power in Gansu and Xinjiang, in Northwestern China, of about 30% (NEA, 2016). To solve this problem, China aspires to build a national grid to carry electricity from where it is generated to where it is needed (Chen and Stanway, 2016), which is mostly to distant cities in the East.

System operators and regulators might find it valuable to have among their options a technology that supplies large amounts of dispatchable renewable power–under some configurations even baseload power–to help control the reliability of the grids, such as concentrating solar power equipped with thermal storage. This technology can be expanded on a large scale to be built in remote, sparsely inhabited regions or on land with low-competing land use for agriculture. In so doing, it can minimize land-use conflicts, particularly in densely populated regions, in regions with high or rapidly increasing electricity demand, and in regions competing for land for agricultural purposes, as seen in both China and the United States–desert regions are low-competition land and the most suitable places in terms of solar irradiation for concentrating solar power for operations.

China and the United States have desert regions endowed with considerable solar potential for concentrating solar power to operate, which places them in a better position than Europe, where most of the research on this technology has focused on the past (Trieb, 2006; Trieb *et al.*, 2014), despite the fact that the largest solar resources ideal for concentrating solar power lie outside its borders in the Saharan and Arab deserts. However, the desert regions in China and the United States are far from high-consumption centers. The greatest solar resources in China are in the Western region, far from the high-consumption centers on the East Coast, while greatest solar resources in the United States are in the Southwest, whereas most consumption centers are on the West and East coasts. This configuration requires the construction of long transmission lines to transmit electricity along 1,000 to 3,000 km or more from the desert regions to where electricity is needed most. Here, I investigate the cost and transmission requirements to supply large-scale controllable solar power to consumption centers in China and the United States. In doing so, I calculate the electricity cost of supplying baseload power and of supplying controllable solar power to meet the demand curves of countries' electricity grids. The objective of power system modeling is to minimize system cost, so the results provide the most techno-economically feasible fleet and transmission configuration given the input constraints, which are solar irradiation level, geographical features, construction and operation costs, and hourly demand curves.

Summary of Contribution II's results

1. **Policy decision: Provision of controllable and baseload power from highest- and second-highest solar resources**

   The findings show that a fleet of concentrating solar power plants with thermal storage operated in a coordinated manner can help to integrate intermittent renewables in China and the United States, supplying not only baseload but also power on demand to meet the constant demand for electricity at very different costs to consumers. In China, the cost of generating and transmitting solar power to consumption centers on the East Coast is reasonable if the plants are located in Tibet, the Chinese region where solar irradiation is the highest and thus where the generation cost might be lower. If financing and other considerations are kept equal, the costs are about 19–20 cents per kWh when following the electricity demand curve and supplying baseload power. The average direct normal irradiance level in Tibet is about 2,600 kWh/m^2 per year, like that in Northern Africa, while the next highest is outside the Tibetan borders, in the Qinghai Province, with and average direct normal irradiance of about 2,100 kWh/m^2 per year, similar to Southern Spain. The cost of supplying concentrating solar power from Qinghai Province to consumption centers on the East Coast are 60–70% higher than from Tibet. At the time of these calculations, the FiT for concentrating solar power in China was about 19.2 cents per kWh, similar to the cost of supplying electricity from Tibet. Hence, from a cost perspective, it might be more attractive to build the plant's fleet in Tibet. Yet, there may be political reasons not to base a part of the future of China's electricity supply on Tibetan resources. Indeed, all concentrating solar power capacity installed and currently under construction in China are outside the Tibetan borders (Lilliestam *et al.*, 2017).

Empirical plant data shows that the concentrating solar power plants under construction in China that are equipped with 6–15 hours of thermal storage and, hence, can supply power on demand benefit from a FiT of about 17 cents per kWh (Lilliestam *et al.*, 2017). This price is 2 cents per kWh lower than the one estimated in this contribution, yet it accounts only for generation costs. The plants that are built or under construction are mainly in Qinghai, Gansu, and Inner Mongolia, whereas I show that transmitting power from Qinghai (or Tibet) to consumption centers in the East adds 1–2 cents per kWh to the generation cost.

Policymakers in the United States might also find it valuable to benefit from the best solar resources and supply solar power to all states, even if these are faraway on opposite coasts. Results show that a fleet of concentrating solar plants in those locations where a plant has already been built or where there is one under construction or in a planning phase would supply electricity at 39–41 cents per kWh when following the demand curve and about 2 cents per kWh higher when supplying baseload power. The average direct normal irradiance level in these locations is a few percent lower than the solar resources in the sites in Tibet, yet the electricity costs are much higher because of the need to increase storage capacity and mirror field extensions to overcome cloudy periods without sunshine because of the North American Monsoon. If the plants could be installed where solar resources are at least minimal to operate, a fleet of plants in Nevada, Arizona, Colorado, New Mexico, and Texas (and not only in Nevada and Arizona) would supply electricity at 2 cents per kWh lower than in the previous scenario. The remuneration for concentrating solar power plants operating in the United States is about 15 cents per kWh (Lilliestam *et al.*, 2017), which is about 60% lower than the results of the scenario examined here, yet these plants in operation have few hours of storage.

The findings suggest that the cost of supplying fully dispatchable electricity to centers of demand in the United States is not economically feasible, given the current remuneration, yet relaxing the reliability of the electricity constraint from meeting the demand 100% of the time to 10–20% lower than that found in fossil fuel power plants would make the electricity supply more economically attractive.

2. Policy decision: Deployment of long-distance transmission

The findings show that, for the four scenarios mentioned above, transmission represents less than 7% of the total electricity cost for consumers. These findings imply that the cost of transmission might not be a deterrent for the success of such large-scale projects, but the challenges to build these projects on the ground might be very different for both countries. If such fleets were built in the United States to supply solar power to consumption centers on both coasts, it would be necessary to build transmission lines over 1,700 km to reach consumers in Houston or over 4,000 km to consumers in Boston. Such transmission projects might be notoriously difficult to build in the United States, as the lines may need to cross several states and regulatory environments, but it can still happen. A couple of years ago, the Department of Energy approved a new HVDC line that will extend from western Oklahoma to western Tennessee (Roberts, 2016). It will bring the abundant wind power of sparsely populated Oklahoma to dense population centers in the East. The process began in 2009 and involved years of reviews, community meetings, and regulatory approvals from multiple agencies (Roberts, 2016). Obstacles to its approval are the lack of direct benefits to states along the path of the line where there would be no power exchanges, political preferences for local resources, even if the costs were higher, and the navigation of several overlapping jurisdictions, multiple state and local authorities, and federal rules. Every landowner and stakeholder must have a say (Hurlbut *et al.*, 2017). If the new long-distance transmission is really necessary to unlock the potential of perfectly controllable solar power, maybe there is reason to discuss how to change the approval process, that is, how to streamline and centralize transmission decision making. Making these projects a reality really fast (as climate science suggests) might involve some compromises, yet they might not be nearly as dreadful as unrestrained climate change.

Instead, China builds such projects in a different way. The central government decrees the project to follow the goals defined in its Five-Year plans, and the lines finish construction in a few years, with different consideration seen in the United States for the local communities in the line's path.

1.10. Synopsis of Contribution III: Impact of political and economic barriers for concentrating solar power in Sub-Saharan Africa

If temperature targets to limit global warming are to be met, affordable but variable power is likely to increase in developing countries. African countries would need controllable power that could integrate the variable power in the grid and meet electricity demand at all times. Hydropower can provide this type of power; yet, hydropower in Africa has been exposed to severe drought conditions that reduced the water level in dams and, consequently, led to electricity blackouts in domestic and regional power systems (Conway *et al.*, 2018). Research shows that reliability concerns related to hydropower performance could trigger challenges presented by weak governance and risk aspirations to maximize the economic and social development opportunities in Africa (Conway *et al.*, 2018). Therefore, a technology would be especially valuable that generates controllable power with a lower exposure to climate-related risks that is, hence, exempt from climate-related shortages in generation.

Concentrating solar power equipped with thermal storage is a climate risk-free technology that can supply controllable power and minimize the strain of variable power on the grids. The electricity mix in Africa heavily relies on fossil fuels about 65%, with almost the 40% of that being coal (IMF, 2017). If renewable power is to substitute for fossil fuel power, it would be beneficial for concentrating solar power with thermal storage to become cost-competitive with other dispatchable fossil fuel sources of power, such as conventional coal power. However, the deployment of a large-scale generation and transmission infrastructure in Africa depends on many political, institutional, financial, and technical challenges, as well as the (perceived) risks of investors to invest in renewable energy projects. Because of these challenges, the cost of electricity from concentrating solar power plants might not be affordable to consumers. The Paris Agreement acknowledges the need to make carbon-neutral electricity affordable, especially in Africa: mandates developed countries provide financial resources and enhance technology transfer; and calls for countries to enhance their cooperation capacities[3]. Here I investigate how much policy instruments address political, economic, and technical challenges encountered in sub-Saharan countries matter to make controllable concentrating solar power an affordable electricity option in sub-Saharan Africa.

As coal is today the cheapest dispatchable power option in sub-Saharan Africa, I use its cost of generation as a metric to examine the affordability of concentrating solar power at the point of demand. The cost of coal power is assumed to be the same across the continent, though costs will vary across countries. Costs depend, for example, on the country-specific financing risk or the availability of domestic coal resources. The comparison is to be understood as a tool to help assess whether

[3] Capacity building is generally accepted to refer to external intervention in the support of capacity and targets a range of actors and systems (e.g., individuals, institutions, and broader economic and regulatory capacity).

concentrating solar power with thermal storage is, under the scenario's conditions, an economically attractive option for sub-Saharan African countries. I assume a period of about 10 years until the solar plants reach the ground. Thus, I assume that, by 2025, the plants will start operation and their electricity costs can then be compared to those of functioning coal power plants.

Summary of Contribution III's results

1. **Policy decision: Reduction of financing costs to levels found in industrialized countries**
   I examine the importance of the perceived risks of both equity investors and lending financial institutions on the cost of concentrating solar power plants and the associated transmission infrastructure required to transmit power to consumption centers. Results show that finance is the most important aspect to address to make concentrating solar power affordable to consumers across sub-Saharan Africa. Results show that policy instruments to de-risk financing costs (some countries have financing costs higher than 20%, the lowest being South Africa with 9.5%) to levels found in developed countries (5%) are crucial to making concentrating solar power an attractive investment option. The cost from concentrating solar power becomes competitive with that of coal power in all sub-Saharan countries as the levelized electricity cost decreases to below 7.3 cents per kWh. De-risking measures on investments can decrease the electricity cost from concentrating solar power to half in Western, Central, and Eastern African countries where the financing risks are high. The impact is smaller for Southern African countries because the financing risks there are already lower. Therefore, results imply that the measure that would reduce the cost of concentrating solar power the most is to provide low-risk finance through dedicated de-risking policies, such as long-term power purchasing agreements and concessional loans.
2. **Policy decision: Reduction of investment costs to levels found in industrialized countries**
   I examine the importance of enhancing technology transfer in developing countries. Results show that reducing investment costs to those levels found in developed regions makes a difference for the competitiveness of concentrating solar power. Results show that when the investment cost of concentrating solar power plants in sub-Saharan countries is the same as that in industrialized countries, the cost of electricity in Western, Central, and Eastern countries decreases about 3 cents per kWh, while in Southern Africa, it decreases about 0.4 cents per kWh, where investment costs are closer to those found in industrialized countries. The electricity costs in Southern Africa are the lowest not only because investment costs are lower than in other sub-Saharan regions, but also because the power lines to reach the best solar resources are shorter. This scenario shows that issues such as weak infrastructure or the lack of skilled labor are important aspects, but they are not crucial for the competitiveness of concentrating solar power, particularly not in Southern Africa.
3. **Policy decision: Enhancement of cooperation capacity to expand power trade outside power pools' borders**

Countries may face the decision of benefiting from the best possible solar sites that are in some faraway place or from solar resources confined within the power pool. Results show that improving the cooperation capacity between power pools could improve concentrating solar power costs slightly, but at the cost of complex trading schemes between many countries and existing administrative borders (e.g., outside existing free-trade areas, which also define the power pools). Therefore, allowing power trades between power pools compared to transmitting power within countries confined in a power pool leads to a cost reduction in Eastern and Western Africa of about 1 cent per kWh, while costs are reduced up to 5.7 cents per kWh in Central Africa, making concentrating solar power in some countries there roughly competitive with coal power. In Southern Africa, there is no difference, as the countries within the power pool already have access to excellent, relatively low-risk solar resources.

Results also show that, for most sub-Saharan countries, importing electricity from concentrating solar power from those locations with the best solar resources within a power pool is cheaper than generating it domestically. Countries such as Niger, South Africa, Namibia, Cameroon, and Kenya have no reason to import concentrating solar power, as they have good solar resources available domestically. Imports are beneficial from a cost perspective in all other cases. The World Bank Country Director for Ghana, Sierra Leone, and Liberia, Henry Karali, highlighted that power pooling in West Africa is a way to increase energy security (MG, 2018). The findings suggest that it could also be a way to benefit from the most economic controllable solar power and for all other African power pools.

Last, I examine the cost competitiveness of concentrating solar power when simultaneously allowing power trade beyond the limits of a country or the limits of a power pool, improving financing conditions to levels found in developed countries, and assuming that the investment costs are the same as those found in industrialized countries. Under these conditions, concentrating solar power is competitive with coal power in all countries with costs around and below 5 cents per kWh. This ambitious scenario shows that concentrating solar power with thermal storage is the cheapest dispatchable option of all, if policy instruments to remove current barriers on renewable energy are in place. Finally, findings also show that transmission costs are not a main driver for the cost competitiveness of concentrating solar power, as they add roughly 1–2 cents per kWh per 1,000 km-line. The construction of such long-distance transmission infrastructure in sub-Saharan Africa, however, encounters more obstacles than those observed for similar projects in the United States and especially in China, challenging the realizable potential of such infrastructure on the ground. The Inga 3 dam project exemplifies a long-distance transmission project that seemed economically attractive, yet the numerous obstacles encountered during the decades and the insufficient institutional cooperation capacity of the countries involved, prevented the project from its realization.

CHAPTER 2. Contribution I: Blue skies over China: The effect of pollution-control on solar power generation and revenues

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Abstract

Air pollution is the single most important environmental health risk, causing about 7 million premature deaths annually worldwide. China is the world's largest emitter of anthropogenic air pollutants, which causes major negative health consequences. The Chinese government has implemented several policies to reduce air pollution, with success in some but far from all sectors. In addition to the health benefits, reducing air pollution will have side-benefits, such as an increase in the electricity generated by the solar photovoltaic panels via an increase in surface solar irradiance through a reduction of haze and aerosol-impacted clouds. We use the global aerosol-climate model ECHAM6-HAM2 with the bottom-up emissions inventory from the Community Emission Data System and quantify the geographically specific increases in generation and economic revenue to the Chinese solar photovoltaic fleet as a result of reducing or eliminating air pollution from the energy, industrial, transport, and residential and commercial sectors. We find that by 2040, the gains will be substantial: the projected solar photovoltaic fleet would produce between 85–158 TWh/year of additional power in clean compared to polluted air, generating $6.9–10.1 billion of additional annual revenues in the solar photovoltaic sector alone. Furthermore, we quantify the cost of adopting best-practice emission standards in all sectors and find that the revenue gains from the increased solar photovoltaic generation could offset up to about 13–17% of the costs of strong air pollution control measures designed to reach near-zero emissions in all sectors. Hence, reducing air pollution in China will not only have clear health benefits, but the side-effect of increased solar power generation would also offset a sizeable share of the costs of air pollution control measures.

1.1. Introduction

Air pollution is the largest environmental cause of health damage and premature death worldwide (Landrigan *et al.*, 2017). More than 90% of the world's population lives in places where air pollution levels surpass the limits specified by the World Health Organization (WHO, 2016). Almost every major Chinese city exceeds the limits for air pollutants recommended by the WHO, leading to some 1.1-1.6 million premature deaths annually (HEI, 2017; Landrigan *et al.*, 2017; Rohde and Muller, 2015; World Bank, 2016a). As a result of health impacts and forgone labor productivity, the gross domestic product (GDP) of China is decreased by up to 11% (World Bank, 2016a), and this value is increasing as China becomes more urbanized and its industrial production increases. Although reducing air pollution has clear health benefits, the monetary effects of such measures are difficult to robustly quantify, which makes arguments for expensive but effective pollution controls harder to justify. Recent aerosol modeling using satellite-derived data has quantified the effects of air pollution on surface solar irradiance (Li *et al.*, 2017). Here we examine the relationship between the cost of adopting sector-specific clean-air policies and the revenues created for the solar industry from different possible regulatory mechanisms via an increase in solar generation as a result of clearer skies. We disaggregate the effects on a sectoral basis using actual anthropogenic emissions data coupled to a global aerosol-climate model. This then allows us to quantify the economic benefits associated with different clean-air policies and their costs.

1.2. Background

Air pollution originates mainly from the burning of biofuels and fossil fuels, primarily coal. China is the world's largest producer, consumer, and importer of coal, and it is responsible for almost half of global coal consumption (IEA, 2017b), thereby emitting large quantities of pollutants, including sulfur dioxide (SO_2), nitrogen oxide (NO_x), ammonia, and carbonaceous aerosols, with large impacts on the environment and on health. To improve air quality from today's level to non-harmful levels, it is necessary to implement aggressive clean-air policies. The Chinese central and municipal governments have implemented anti-pollution measures similar to those in industrialized economies. These include the installation and operation of pollution-control equipment on major point sources, such as coal power plants, and also on motor vehicles; the replacement of the burning of coal for residential and commercial heating with natural gas or propane; the closure of industrial plants where pollution-control equipment is not economically feasible or plants located in densely populated areas; and the gradual replacement of coal power with renewables, such as solar and wind power (Crane and Mao, 2015). Although some of these policies have been successful, they do not represent the best possible outcomes: coal-burning power and industrial plants can be retrofitted with state-of-the-art pollution-control equipment to reach near-zero emissions similar to or even lower than those from a natural gas combined-cycle unit; road transport and navigation can switch to cleaner fuels with lower content of sulfur and install stricter pollution-control equipment; and residential and commercial heating and cooking can be switched from coal to natural gas nationwide (Crane and Mao, 2015; ICCT, 2015a; World Coal Association, 2017). The partial success of pollution control shows that cleaner air is possible, but it also shows that it is not easy and that the success of such policies is uncertain. In this article, we investigate the effect of pollution control on solar radiation, assuming that highly ambitious policies are implemented successfully.

To control air pollution and greenhouse gas emissions, China aims to consume 20% of its primary energy from non-fossil sources by 2030 (Su, 2015), for which renewable energy sources are crucial. China has the largest solar photovoltaic (PV) fleet worldwide (Bloomberg NEF, 2017), and the National Energy Administration recently increased the previous 2020 target of 105 GW to 200 GW (Osborne, 2017), and the National Renewable Energy Centre foresees 400–600 GW by 2030 and 700-1300 GW by 2040 (CNREC, 2014). Air pollution, however, reduces the solar radiation that effectively reaches solar panels, reducing the power generation of the PV fleet (Li *et al.*, 2017). Globally, this is a minor problem: on average, anthropogenic aerosol particles reduce the net radiative flux by -0.9 W/m^2 (range from 0.1 W/m^2 to -1.9 W/m^2) at the top of the atmosphere (Boucher *et al.*, 2013). However, regionally, solar dimming at the Earth's surface can be much larger, as vividly evidenced during smog events around the world. Air pollution affects solar power generation through three main mechanisms. First, particle matter accumulates on the solar panels (Boyle *et al.*, 2015), which reduces generation until the panels are washed. Second, aerosol particles such as sulfate, black carbon (BC), organic carbon (OC), and sea salt or dust particles, interact in ways that scatter (and sometimes absorb) solar radiation (Boucher *et al.*, 2013). Third, cloud formation caused for example by the reaction of SO_2 with other pollutants, creating aerosol sulfate particles, absorbs moisture from the air and can serve as cloud condensation nuclei (certain aerosol particles also as ice nuclei), thereby increasing cloud reflectivity (Twomey, 1977) and lifetime (Albrecht, 1989) and decreasing the solar radiation reaching the Earth's surface.

Most industrialized countries, including those of the European Union and the United States, have adopted stringent air quality standards, primarily out of a concern for the human health impacts of ground-level pollution, but also causing substantial economic cost (ICCT, 2015b). China has been moving in this direction, but nevertheless lags behind in terms of air quality. Given the ministerial decision-making structure of the Chinese government, there is reason to believe that an appraisal of the costs and benefits lying entirely within the Chinese energy system, of such pollution control policies, could provide a politically salient argument for accelerating the improvements in Chinese air pollution.

1.3. Methodology

We perform a cost-benefit analysis to compare the cost of the measures on the fossil-fuel sectors to reach near-zero emissions with the increase in revenues created for the solar industry. We do this in three steps.

First, we estimate the cost of implementing clean-air policies on various fossil-fuel sectors, namely the energy, industrial, residential and commercial, and transport sectors. For each sector, we estimate the cost of implementing sector-specific best-practice emission standards and apply the cost functions to sector-specific emissions. The emission data are from the bottom-up emissions inventory Community Emission Data System (CEDS) (Hoesly *et al.*, 2017).

Second, we model the effect of eliminating anthropogenic emissions on surface solar irradiance with the global aerosol-climate model ECHAM6.3-HAM2.3 and disaggregate the effects of different pollution control measures in each sector. To estimate the effect of emissions on surface solar irradiance, we estimate both the direct effect of aerosol particles (scattering and absorption) on solar radiation and the semi- and indirect-effects of aerosol particles on cloud formation and life-time. We acknowledge that emissions in the future can change, and indeed that is a prerequisite for our study: the Chinese policies have strongly reduced emissions from power stations, and the next steps can be to strongly reduce industrial, commercial and transport-related emissions.

Third, we estimate the increase in electricity generation from solar PV panels as a result of an increased surface solar irradiance due to a reduction in emissions and calculate the revenues for the solar industry from the current market feed-in tariffs (FiTs) and future feed-in prices into the electricity grid. We discount the future revenues for two different discount rates to account for various discounting strategies in the private sector. Figure 1 introduces the framework with which to estimate the cost of adopting best-practice emission standards and the economic gains to the solar industry from clean air.

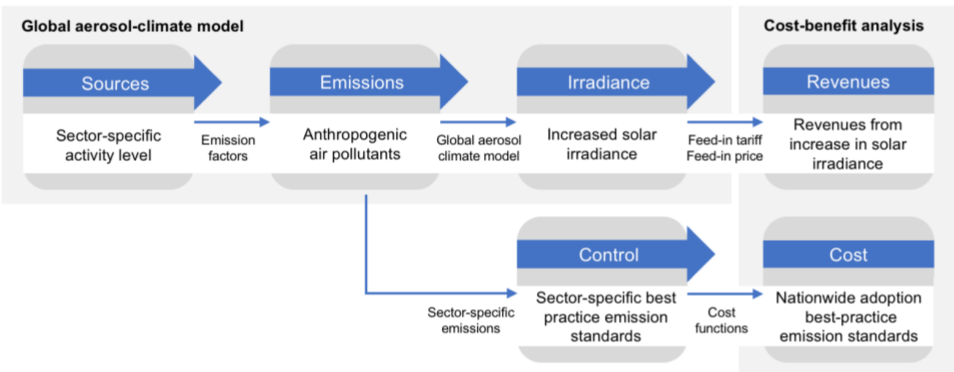

Figure 1 Framework for evaluating the cost of clean-air policies and the revenues to the solar industry.

To perform the cost-benefit analysis we use the following net present value (NPV) model:

$$\boldsymbol{NPV} = \sum \left[\frac{\boldsymbol{Cost_n} - \boldsymbol{Revenues_n}}{(\boldsymbol{1}+\boldsymbol{r})^{\boldsymbol{n}}}\right] \tag{1}$$

where *Cost* is the cost incurred to investors as a result of adopting best-practice emission standards (described in the following section *Clean-air policies and their cost*), *Revenues* is the revenues to the solar investors from the feed-in tariffs (FiT) and feed-in price from increased solar irradiance (described in section *Revenues to solar investors*), *n* the number of years between 2016 and the target years, and *r* the discount rate.

Clean-air policies and their cost

Here we briefly introduce the air pollution control measures on current fossil-fueled installed capacity and transport fleet. See section A1 in Appendix A for a detailed description of the methods and calculations for the estimation of the sector-specific costs to adopt best-practice emission standards. We assume that future assets will be near-zero emitters as a result of new standards and hence, reaching near-zero emissions for these assets comes at no additional cost.

Electricity generation: China is leading an ambitious, multi-front campaign to clean up the air (Crane and Mao, 2015). In the power sector, China is mothballing older coal-fired power plants and reducing emissions from existing plants by retrofitting them with air pollution control technologies (Crane and Mao, 2015). Several coal-fired power plants have become early adopters of near-zero emission control technologies, resulting in emissions that are lower than the most stringent regulation limits for coal plants and also below the limits for natural gas turbine plants: PM 5 mg/m^3, SO_2 35 mg/m^3, and NO_x 50 mg/m^3 (World Coal Association, 2017). Here we assume that combustion processes in fossil-fueled power plants are equipped with emission-removal technologies to achieve near-zero emissions.

The combustion process for heat generation due to electric boilers that generate heat for sale to third parties, such as residential, commercial, or industrial consumers, can be equipped with similar air pollution control systems as is used in fossil-fueled power plants (World Bank, 2018a). The same applies to the transformation processes, including coal coke production, oil refining, and charcoal production. We estimate that the total retrofitting cost in the energy sector, i.e., electricity and heat generation plants and transformation processes, is $7.2–11.4 billion/year.

Industrial combustion and industrial processes: Although emissions from coal-fired power plants and coal-fired industrial boilers are affected by a number of variables, such as coal type and composition and the type of combustion technology, the emission control technologies used to limit emissions of flue gases are similar (World Bank, 2018a). Hence, we assume that coal-fired industrial boilers are retrofitted with the same combination of air pollution control systems as is used in coal-fired power plants, and thus the total cost is $12.0–19.1 billion/year.

In addition to the emissions from combustion processes in industry, the sector emits process emissions that occur (a) as a result of the thermal decomposition of substances, (b) of reactions between substances or their transformation, such as the chemical or electrolytic reduction of metal ores, and (c) during the creation of substances for use as feedstock (EEA, 2016). In China, most of the process emissions originate from the metal production industry, the chemical industry, and the pulp and paper industry. Emission control technologies for process emissions are process-specific and strongly dependent on the quality of raw materials. The literature available on the costs to limit processes' emissions is limited. Hence, we acknowledge some uncertainty regarding the costs to limit these emissions, which account for ~15% of total SO_2 emissions, the pollutant with the highest influence on reducing solar surface irradiance. We thus estimate that the cost of retrofitting the industrial processes is $4.2–6.7 billion/year.

Road transport and domestic navigation: We estimate the cost of reaching near-zero emissions from road transport and domestic navigation by switching to near-zero-sulfur 10 ppm (parts per million) fuels. The costs of reducing sulfur content in the fuel depend on the state of existing refineries, current fuel quality, and emissions standards but such costs can be divided into two types: the cost associated with fuel production and the cost associated with vehicle emission control technologies. Estimates of the costs associated with fuel production accounts for upfront refinery investment, such as capital equipment upgrades, and direct operating costs, such as catalysts and chemicals (ICCT, 2015a). Estimates of the cost for the introduction of advanced emission control technologies in vehicles account for the additional costs to manufacturers for equipping these vehicles with advanced emission control technologies to meet international best-practice standards, i.e., the adoption of the China 6 standard in gasoline and diesel vehicles. The adoption of international best-practice standards such as ultra-low sulfur standards and the China 6 standard costs $11.7 billion/year.

For marine vessels, switching from high-sulfur heavy fuel oil (HSFO) to low-sulfur marine diesel or gas oil (MDO/MGO) is a straightforward solution because engines do not need to be retrofitted with emission control technologies to accept this type of fuel, although minor adjustments in auxiliary equipment are needed in some cases. We estimate the cost of retrofitting the oceangoing container vessels in Chinese waterways to use MDO/MGO, i.e., installing a fuel cooler or chiller and the associated piping prior to the fuel pump to decrease fuel viscosity, and selective catalytic reduction (SCR) technology. The total cost of retrofitting the container fleet is $3.6 billion/year. We exclude emissions from rail transport because these account for only 3% of SO_2 emissions from the transport sector alone.

Residential and commercial sector: To improve air quality, China has started to replace coal-fired residential heating and cooking in northern Chinese cities with gas-powered stoves and boilers, or with those using electricity from renewable energy (Crane and Mao, 2015). We estimate the cost of replacing coal with gas from natural gas pipelines and liquefied natural gas imports for the residential and commercial sector. Switching from coal to gas involves the construction of natural gas distribution networks, pipelines, and household connection facilities, the prices of which are uncertain. The data on the installed capacity of residential and commercial boilers, and the cost of converting a coal-fired boiler to a natural gas-fired boiler are also uncertain. Hence, we acknowledge these uncertainties and exclude these estimates from our calculations. We estimate that the cost of replacing coal with natural gas for residential and commercial use is $9.9–16.1 billion/year.

Effect of clean-air policies on surface solar irradiance

We construct several emission scenarios that replicate the policy changes driving emission reductions, and quantify the geographically specific changes in surface solar irradiance as a result of reducing or eliminating sector-specific air pollutants. Reference (Li *et al.*, 2017) quantified the impact of aerosols on surface solar irradiance in China using satellite observations, which account for all aerosols. Aerosols, however, can be of anthropogenic (e.g., power plants, slash-and-burn agriculture, incinerators, cooking stoves, and vehicles) or natural origin (e.g., volcanoes, dust storms, and forest fires). In estimating the impact of aerosols from anthropogenic sources only, satellite observations are uncertain data sources, because the aerosol origin cannot be easily determined, making it difficult or impossible to assess the impacts of sector-specific measures using satellite data. Some studies have attempted to identify aerosol origin from a combination of satellite observations and models (Bellouin *et al.*, 2013; Kinne *et al.*, 2013) but these only differentiate between anthropogenic and natural aerosol origin and provide no sector-specific data. Here, in contrast to (Li *et al.*, 2017), we use region- and sector-specific emission data to model the effect of anthropogenic emissions on surface solar irradiance using a bottom-up approach and disaggregate the effects of current emissions and of pollution control measures in each sector.

To examine the effect of anthropogenic aerosols on surface solar irradiance, we use the global aerosol-climate model ECHAM6-HAM2, which consists of the global climate model ECHAM6 (Stevens *et al.*, 2013) and the aerosol module HAM2 (Stier *et al.*, 2005; Zhang *et al.*, 2012). The global aerosol-climate model ECHAM6-HAM2 allows us to identify the impact of single anthropogenic aerosol species and examine sector-specific pollution control scenarios. Here, we use the latest model version, ECHAM6.3-HAM2.3, and calculate the direct effect of aerosol particles (scattering and absorption) on solar radiation and the semi- and indirect-effects of aerosol particles on cloud formation and life-time.

ECHAM6.3-HAM2.3 has a two-moment-cloud microphysics scheme (Lohmann and Hoose, 2009; Lohmann *et al.*, 2007) to compute the interactions of aerosol particles with stratiform liquid, mixed-phase, and ice clouds. The interactions of aerosol particles with convective clouds are not explicitly included, but the convection scheme ((Tiedtke, 1989), with modifications by Nordeng (1994) for deep convection) uses the dependence of the detrained cloud droplets (i.e., for liquid clouds only) from convective clouds, on number concentration of activated cloud condensation nuclei at the base of the convective clouds.

In the climate model ECHAM6.3, we compute the radiative transfer using the broadband radiative transfer model Psrad (Pincus and Stevens, 2013). Psrad uses 14 bands for the shortwave and 16 bands for the longwave part of the spectrum. In the aerosol module HAM2.3, we use a sulfur chemistry module based on Feichter *et al.* (1996). The aerosol module computes the life cycle of aerosol particles: the emissions of precursor gases or aerosol particles, the nucleation of new sulfate aerosol particles and condensation of gaseous sulfuric acid on existing aerosol particles, aerosol particle collisions and growth, the water uptake of aerosol particles, the interactions of aerosol particles with radiation and clouds, and the removal of aerosol particles by sedimentation, dry deposition, wet scavenging in clouds, or precipitation below clouds. The aerosol module uses the aerosol species of sulfate, BC, OC, sea salt, and mineral dust particles. Sulfate is computed from SO_2 and dimethyl sulfide emissions. Natural aerosol emissions of sea salt and mineral dust and dimethyl sulfide precursor emissions from the oceans are computed online. Anthropogenic SO_2, BC and particulate organic matter are taken from CEDS for the last available year of data, which is 2014. Observed sea surface temperatures and sea ice cover are for the years 2000-2009 (AMIP simulations). Meteorological variables, including vorticity, divergence, and surface pressure were nudged towards the ERA-Interim reanalysis for the same years (Dee *et al.*, 2011). The model does not compute the impact of climate change on clouds.

We conducted several 10-year simulations (after a 3-month spin-up), varying the emissions from the different sectors in China only. All simulations were performed with a T63 horizontal spectral resolution of 1.9°×1.9° using 31 vertical levels.

The sum over the shortwave bands is the shortwave downward flux at the surface. Here, we refer to it as surface solar irradiance. We estimate the increase in surface solar irradiance by subtracting the modelled surface solar irradiance under certain emissions abatement conditions from the surface solar irradiance under current or specific abatement emissions conditions. Because surface solar irradiance depends nonlinearly on the aerosol-radiation and aerosol-cloud interactions (Figure 3 in Carslaw *et al.* (2013)), it increases further the stronger the emissions abatement, by following a logarithmic growth pattern.

Differences in calculating surface solar irradiance with ECHAM6.3-HAM2.3 and satellite observations such as CERES-SYN1deg, as used in (Li *et al.*, 2017), may appear. This may result from the fact that the version of the CERES-SYN1deg used by (Li *et al.*, 2017) excludes, in the *no aerosol* product, the total aerosol optical depth (i.e. also the aerosol optical depth from background aerosol such as mineral dust, sea salt aerosol, other marine aerosols, biomass burning aerosol, aerosol from vegetation). In ECHAM6-HAM2, background aerosol data are included in all simulations. Differences in surface solar irradiance from ECHAM6.3-HAM2.3 may also appear when compared to surface observations. See section A2 in Appendix A for an evaluation of the modeled surface solar irradiance with ECHAM6.3-HAM2.3 compared to satellite observations from CERES-SYN1deg and surface observation-based estimates.

ECHAM6.3-HAM2.3 does not account for nitrate aerosol and CEDS does not provide data on anthropogenic dust; thus, the results presented in the section *Results and discussion* on reductions in surface solar irradiance are rather an underestimation of what solar irradiance could further be reduced, thereby possibly underestimating the potential additional revenues to the solar industry.

We examine the effect of past and future decisions of reducing or eliminating emissions on surface solar irradiance. For this, we model the effect of reducing sector-specific emissions from past and counterfactual scenarios and the effect of eliminating sector-specific actual emissions to account for future measures.

Figure 2 shows the actual and counterfactual SO_2 emissions from the energy, industrial, residential and commercial, and transport sectors. The counter-factual scenarios describe the “could-have-been” emissions if no emission standards had been implemented since 2006 for the energy sector and the emissions of the industrial sector if the same standards used for electricity generation had been applied to industry as well (section A3 in Appendix A for a description of policies and measures adopted in the past to control air pollution; and section A4 in Appendix A for details on the calculation of the counterfactual scenarios). As seen in Figure 2, the emission standards in the energy sector, mainly thermal power plants for electricity production, worked well: emissions decreased by about 50%, even though coal power generation increased dramatically. In the industrial sector, which includes iron and steel, cement, non-ferrous metal smelting, the chemical industry, and other industry boilers, the SO_2 control measures are much weaker, and emissions are steadily increasing. The emissions of the residential and commercial sectors, mainly from heating, are slowly increasing, and there is no coordinated policy to control these emissions. Table D in Appendix A shows the sector-specific contributions of anthropogenic SO_2, BC and OC emissions as estimated by CEDS, the latest sector-specific emissions data available.

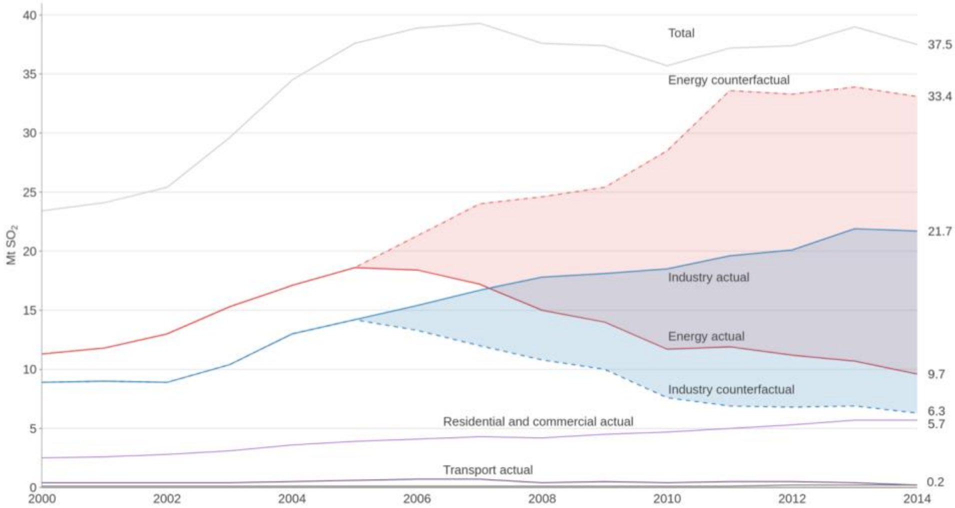

Figure 2 Yearly SO_2 emissions (Unit: megatonnes, Mt) in China. Emissions from energy generation, industry, residential and commercial, and transport sectors based on the bottom-up inventory of anthropogenic emissions Community Emission Data System (Hoesly *et al.*, 2017). Solid lines are actual emissions; the dashed ones are the counterfactual scenarios. The four sectors account for 99% of SO_2 emissions; the remainder comes mainly from waste incineration.

Revenues to solar investors

We estimate the increase in electricity generation from solar PV panels using the modelled net surface solar irradiance from ECHAM6.3-HAM2.3. The increased revenue is thus the difference in income from electricity generation of all solar panels under actual conditions and under the emissions conditions of a specific scenario. We classify the operational grid-connected solar PV installations in China as of December 2016 depending on their locations (for a given latitude and longitude), installed capacities, and operation dates, as given by Bloomberg New Energy Finance (Bloomberg NEF, 2017) (see Table E in Appendix A for cumulative installed solar PV capacities by province and region). Figure 3 shows the distribution of the grid-connected solar PV plants scaled by installed capacity. Bloomberg New Energy Finance does not provide data on the location and capacity of non-grid-connected solar PV projects; hence, we exclude these projects from the remuneration calculation in this analysis.

Figure 3 Distribution of the grid-connected solar PV plants scaled by capacity. Data from Bloomberg NEF (Bloomberg NEF, 2017) under a CC BY license, with permission from (Bloomberg NEF, 2017).

We compute the annual electricity generation E (kWh) from a given fixed (non-tracking) solar PV system as follows:

$$\mathbf{E = A\ r\ I_{tr}\ \eta\ h = \ P_{dc0}\ I_{tr}\ \eta\ h} \tag{2}$$

where A is the total solar panel area (m^2); r is the solar panel efficiency (%); I_{tr} is the increase in surface solar irradiance (kW/m^2); η is the system performance ratio, which we assume as a uniform 0.85 (Dobos, 2014); h are hours in a year, 8760; and P_{dc0} is the nameplate DC rating of the module (kW). We apply a correction factor to the electricity generated to account for optimal panel orientation and tilt based on JRC (2017), see Table F in Appendix A. We calculate the annual electricity generation from 2016 to 2040 for an installed PV capacity of 78 GW in 2016 (Bloomberg NEF, 2017) and future PV capacities according to different scenarios (200, 400–600, and 700–1300 GW by 2020, 2030, and 2040, respectively) (CNREC, 2014; Osborne, 2017). The International Energy Agency projects 469–550 GW of PV capacity by 2030 and 738–835 GW by 2040 (IEA, 2017c), in agreement with (CNREC, 2014). We assume a linear capacity-growth trend from current installed capacities to future capacity scenarios based on current provincial capacity distribution.

We then calculate the revenues for the solar industry from the current market FiT and future feed-in prices into the electricity grid. To calculate the potential remuneration from each grid-connected PV project, we multiply the project-specific annual electricity generation by the region-specific FiT scheme. We do so for all operational grid-connected solar PV projects and calculate the total remuneration. See section A8 in Appendix A for information on the compensation level of the FiTs depending on the region and starting date of the compensation.

It is expected that the FiTs for new PV projects will decrease over time to reflect decreasing technology costs. We assume that the FiT level, or eventually the feed-in price once the tariff is removed, follows the national utility-scale PV system cost, which was 1,168 $/kW in 2016 (IRENA, 2018b), for two different scenarios. First, we assume that FiTs decrease over time, following a decrease in PV cost under a technological learning rate of 20% starting from 2017, the last year of available FiT data (Table G in Appendix A). See Equation (3) for a description of the learning curve in terms of how the system cost evolves over time (Neij *et al.*, 2003).

$$\boldsymbol{C_{cum} = C_0\, n^b} \tag{3}$$

where C_{cum} is the cost per unit as a function of cumulative capacity, C_0 is the cost of the first unit, n is the cumulative capacity, and b is the experience index. The costs decrease by the learning rate LR = $1-2^b$ for each doubling of cumulative capacity.

In the second case, we assume that no technological learning occurs after 2017, so that both the technology cost and the FiTs are the same as in 2017.

We estimate future system costs given an actual (78 GW by the end of 2016) (Bloomberg NEF, 2017) and future PV capacities as expected by the National Energy Administration and the National Renewable Energy Centre (200, 400–600, and 700–1300 GW by 2020, 2030, and 2040, respectively) (CNREC, 2014; Osborne, 2017). We exclude the revenues from off-grid solar PV installations when estimating the revenues. We discount the revenues to the solar investors using discount rates of 5% and of 8%, which are commonly used on mitigation options in China (ICCT, 2015a; IRENA, 2018b).

1.4. Results and discussion

Cost of air pollution measures for near-zero emissions

The cost of adopting sector-specific nationwide clean-air policies to reach near-zero emissions, for the present market configuration, amounts to $58.6 billion/year, ±$10 billion/year (Table I in Appendix A). The highest cost of pollution control stems from industry because this is the largest polluter, but the specific cost of pollution elimination is different in each sector and also for each pollutant because the processes differ widely. Monetary values are in $\$_{2016}$/kW, exchange rate 0.151 of annual average RMB_{2016}.

Effect of clean-air policies on surface solar irradiance: nationwide

Past air pollution control measures have led to an increase in solar irradiation: compared to the counter-factual emissions levels without pollution control, the air pollution control policies implemented in the energy sector since 2006 have increased surface solar irradiance by up to 3.5% (5 W/m^2) (section A10.1 *Effect of past and counterfactual clean-air policies on surface solar irradiance* in Appendix A*;* Figures B and C in Appendix A for % and W/m^2 results). Yet, there is still room for further improvement considering today's pollution levels. Here we show the effect of decisions to eliminate sector-specific emissions on surface solar irradiance. Results show that the increase in surface solar irradiance due to emissions reduction is non-linear: eliminating today's emissions from the energy sector increases surface radiation by up to 3.5% and eliminating industry emissions as well increases radiation by up to 11% (Figure 4a-b; 6-16 W/m^2, Figure D in Appendix A for W/m^2 results). Eliminating the emissions originating in the residential and commercial (RCO) sector as well, however, increases surface solar irradiance by up to 27% (Figure 4c; 35 W/m^2, Figure Dc in Appendix A). The contribution of emissions from transport is small as compared to those of the other sectors, and removing its emissions as well increases surface solar irradiance only by up to 29%, representing only a slight increase (Figure 4d). Hence, whereas the effects of eliminating emissions in a single sector are small (5% from industry only, 3% from residential and commercial only, Figures Ea-b in Appendix A), the effect of eliminating emissions from all sectors at the same time yields much stronger benefits. This non-linear effect is consistent with results from Carslaw *et al.* (2013) on the effect of anthropogenic emissions on cloud albedo. Removing air pollutants from only one sector will leave large irradiance gains unutilized. It is thus important to focus efforts on all sectors, not only from a health perspective as any removal of air pollutants contributes to improve health (WHO, 2016).

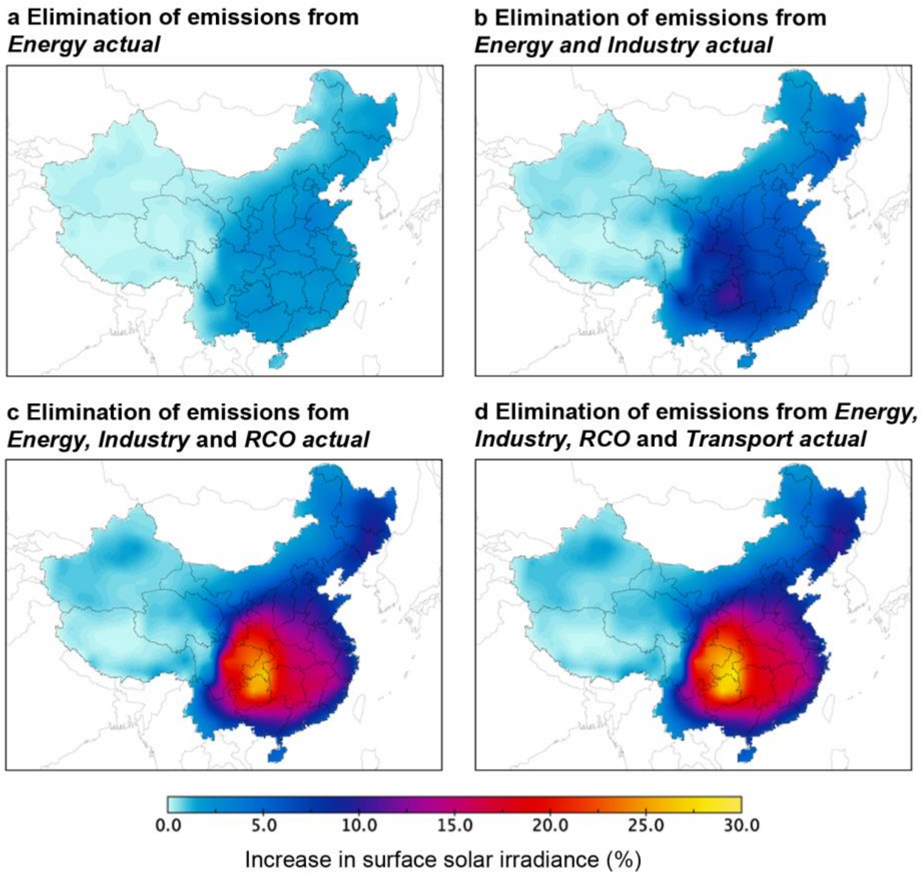

Figure 4 Increase in surface solar irradiance in percent (%). From an elimination of actual SO_2, BC, and OC emissions from energy sector (a), of actual emissions from energy and industrial sectors (b), of actual emissions from energy, industrial and residential and commercial (RCO) sectors (c), and of actual emissions from energy, industrial, RCO, and transport sectors (d). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

Figure 5 summarizes the effect of adopting a multi-sector approach to eliminate all emissions compared to eliminating emissions from single sectors only on the average national surface solar irradiance. Haze pollution became a primary concern for air quality in most Chinese cities, especially those in the Beijing-Tianjin-Hebei region. As a result, local governments in this region aim to change the heating systems in the residential sector from coal to natural gas burning because of the significant contribution of residential emissions to local air pollution (Liu *et al.*, 2016). Here we show that the effect of eliminating residential emissions only, or those from the energy and industry sectors only on surface solar irradiance is smaller than when adopting a multi-sector sector approach. The largest effect on surface solar irradiance will be achieved when not only the emissions from the energy and the industrial sectors, i.e., the sectors that have received the most attention regarding reducing their emissions, are eliminated completely but also the emissions from the RCO sector. Once emissions from the RCO sector are removed, surface solar irradiance increases by more than twice as much as with eliminating emissions from the energy and industrial sectors only, as well as by more than five times as much with eliminating emissions from the energy sector only.

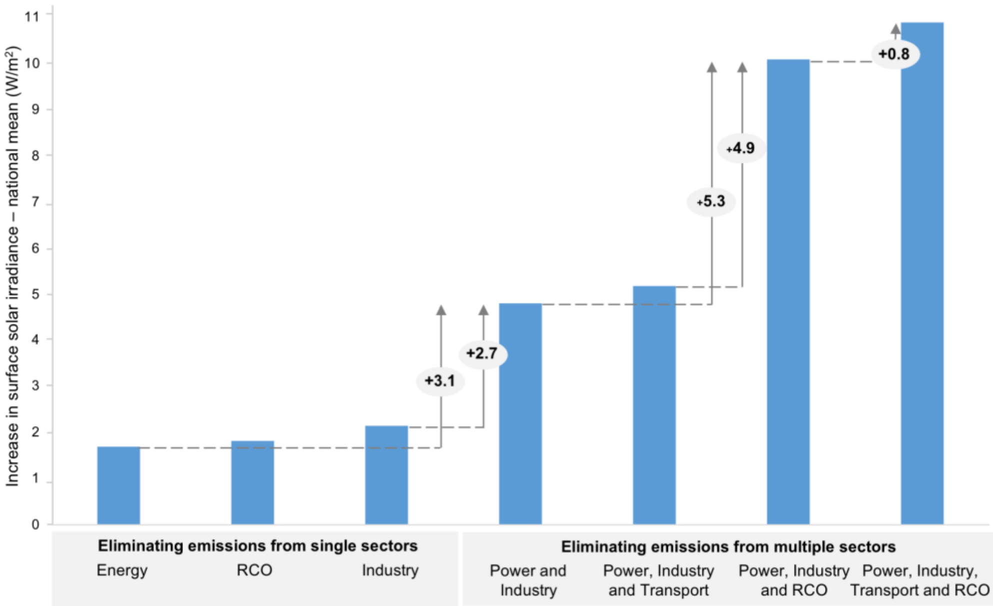

Figure 5 Breakdown of increases in surface solar irradiance (national mean, W/m^2). From an elimination of SO_2, BC, and OC emissions from single sectors: the energy, residential and commercial (RCO) or industrial sectors; and from multiple sectors at the same time: the energy and industrial sectors, both sectors with RCO, and all four sectors together. The national mean is the area-weighted mean increase in surface solar irradiance. The numbers are valid if pollution control happens for the stated single or combined strategies, as the effect is not linear: the relative contribution of each sector is sensitive to the order of pollution measures. Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

Effect of clean-air policies on surface solar irradiance: province-specific

As seen in Figure 4 and 5 above, the effects of pollution control on irradiance can be strong, but they are geographically heterogeneous. Disaggregating the effect to province-specific numbers reveals just how much this can be. The provinces located in the geographic center of China (Chongqing, Guizhou, Hunan, Hubei, Shaanxi, Jiangxi, Henan), where the irradiance effect is strongest, could increase irradiance by 15%-28%, but because these regions have only ~10% of total installed PV capacity, the economic impact on the national PV fleet would be small. One-third of the Chinese solar PV capacity is installed in areas in Inner Mongolia, Qinghai, Xinjiang and Tibet far away from both demand and pollution centers: there, eliminating emissions would increase surface solar irradiance by less than 5%. Also, in these regions, the effect of pollution on the PV fleet is small. See Figure 6 for the location of the provinces, Figure 7 for province-specific increases in solar surface irradiance for eliminating emissions from all sectors, and Table J in Appendix A for detailed results for an elimination of actual emissions from the energy sector only, from both the energy and industrial sectors, with the transport or the RCO sectors, and from all sectors.

Figure 6 Map of the 31 provinces and the 6 regions of China.

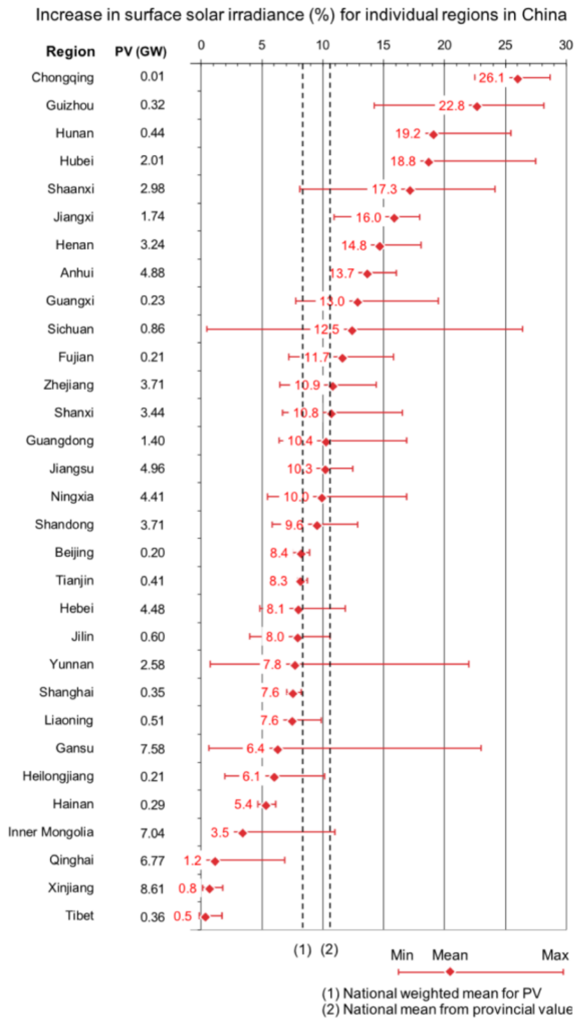

Figure 7 Increase in surface solar irradiance (min, max, mean, %). For eliminating actual SO_2, BC and OC emissions from all sectors. The mean province-specific increases in surface solar irradiance are area-weighted means. The national weighted mean for PV (8.3%) is weighted for province-specific PV capacities. The national mean from provincial values (10.6%) is the unweighted mean of all provinces. Right to the regions is the solar PV installed capacity (GW) per province as of December 2016. Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

Most of the Chinese PV fleet (60%), however, is located near the population centers in the northern, eastern, and southcentral regions, where emissions are high, reducing surface solar irradiance by 5–15%. Given the large current and expected PV capacity of not only large-scale PV plants (Bloomberg NEF, 2017) but also decentralized PV (Rajeshwari, 2018)–as it is beneficial to build PV on rooftops due to the absence of transmission costs, stringent air pollution control measures in these regions will clearly increase the solar power output and hence the profitability of Chinese solar power.

Revenues in the solar industry

The elimination of all aerosol species from all sectors would have increased the generation of the 2016 Chinese solar PV fleet by 10 TWh, or some 14% of the current solar PV generation (NAE, 2018). Today's solar PV generation in China represents about 1% of the final electricity consumption (NAE, 2018), thus the increase in electricity generation compared to the final electricity consumption is still minor. For future projected solar PV fleets, the effect would be 24 TWh for 2020 and 49–73 TWh for 2030, considering a low and a high scenario regarding installed solar PV capacity (Tables J and K in Appendix A for specific increases in solar generation). The increased Chinese PV generation in 2030 is roughly equal to the current electricity demand of a mid-sized European country, such as Austria (Eurostat, 2016)–just from the cleaner air, without a single MW of additional PV installation. By 2040, depending on the installed PV capacity, solar generation could increase to about 85–158 TWh.

The increase in surface solar irradiance would increase the revenues of the solar industry from the FiTs, as the generation of a given solar PV capacity increases: in 2016, removing all actual aerosols emissions from all sectors would have created $1.4 billion in additional revenue from increased generation in the clearer air. This amount is equal to the economic losses from the curtailment of solar power as a result of the grid instability experienced in the same year (Greenpeace, 2017). By 2040, the revenues from increased solar PV generation could reach up to $6.9 billion/year for a discount rate of 5% and when the FiTs decrease over time, and up to $10.1 billion/year for the same discount rate but for FiTs the same as in 2017. See Table L in Appendix A for specific revenues for 2020, 2030, and 2040, for different discount rates, learning rates and capacity expansion scenarios; and Table M for specific non-discounted revenues.

Cost-benefit ratios

The cost of measures in all sectors to reach near-zero emissions amounts to $48.6–68.6 billion, while the revenues depend on several factors as described above, and in 2040 they could reach up to $10.1 billion/year, see Tables N and O in Appendix A for numerical NPV results.

The cost compensation is highly dependent on the size of the PV fleet and FiTs, which are dependent on the technological learning rate: the scenarios with technological learning result in lower profit margins over time as compared to the scenarios without technological learning. Thus, the increased revenues in 2040 could compensate for about 13–17% of the pollution control cost in all sectors and about 16–21% of the combined pollution control cost in the energy, industrial, and RCO sectors (Figure 8 1a-b and 8 2a-b; Figures G and H in Appendix A for results for 2020 and 2030), revealing a low level of marginal cost compensation for eliminating pollutants in the transport sector. Some 14–18% of the cost of eliminating emissions from the energy sector only–which given the past progress could be the sector where strong pollution control could be fastest to implement, could be offset via increased PV revenues. In this case, the revenues and the costs would arise in the same sector–electricity generation–potentially allowing for a direct link between the two, especially if the same actors own both coal and PV generators.

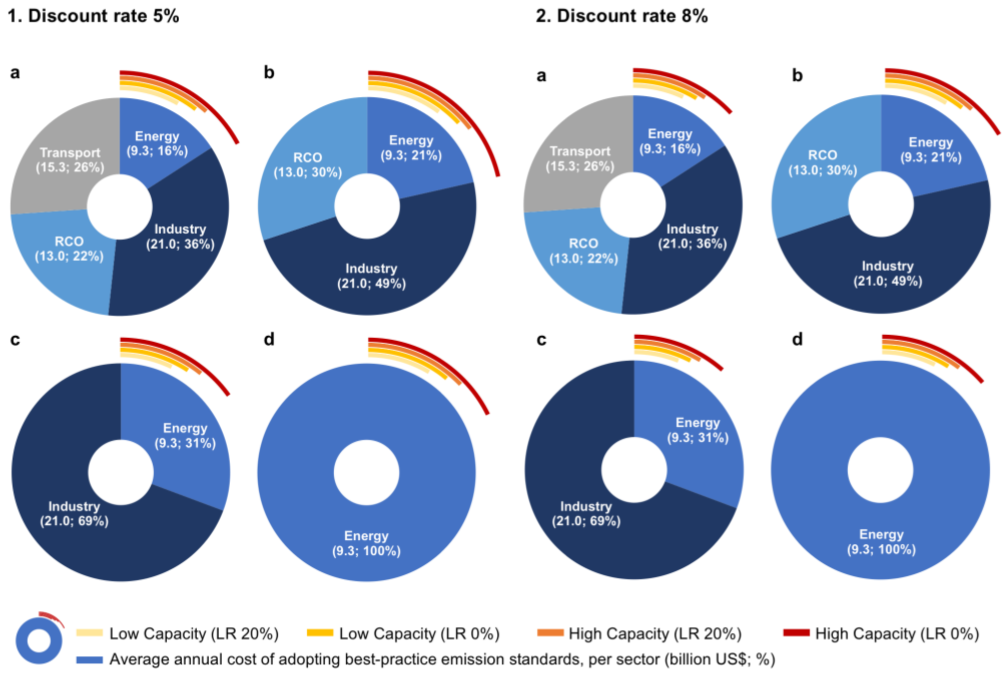

Figure 8-1 and 8-2 Annual average cost (billion $ and %) of adopting best-practice emission standards. To all sectors (a), the energy, industrial and residential and commercial (RCO) sectors (b), the energy and industrial sectors (c), and the energy sector alone (d), compared to the annual revenues (billion $, discounted) leveraged from the feed-in tariff on the Chinese PV fleet in 2040 for a low (700 GW) and a high capacity scenario (1300 GW), and for a feed-in tariff that reduces over time as the national PV system cost reduces following a technological learning rate of 20% starting in 2017, i.e., the year of the last available feed-in tariffs, and for a feed-in tariff without technological learning, i.e., equal to the feed-in tariffs in 2017. Revenues discounted to the present using a discount rate of 5% and 8%. Sector-specific annual costs are averages of a low and a high cost scenario, for a break-down of sub-sector-specific costs and uncertainty ranges see Table I in Appendix A. Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

1.5. Conclusions

Cleaning the air in China is possible through an expansion of best-practice measures for pollution control already implemented in China and elsewhere. Although the cost of doing so would be substantial, it would be societally beneficial–the health impacts of air pollution in China are a two-digit share of GDP. Here, we have shown that the elimination of SO_2 emissions and carbonaceous aerosols will make the air clearer and increase surface solar irradiance, thereby strongly increasing the generation of solar PV electricity. The additional revenue would amount to up to about 20% of the cost of the pollution control measures, showing that there are hard economic benefits for cleaner air as well, in addition to the softer and hard-to-monetize health benefits. Hence, the increased revenue from the relatively minor solar industry already goes a long way towards justifying radical air pollution measures.

We have shown that reducing air pollution is not only an important health and environmental policy, but can also be an important solar power policy measure. Already-implemented policies to decrease the levels of air pollution have aimed to reduce the negative impacts on health but, as a co-effect, have also increased surface solar irradiance and hence solar generation by up to 3.5%. However, the largest effects of past efforts can be seen in regions where the installed PV capacity was comparatively low. The elimination of emissions could increase PV generation from the PV fleet by on average 11%. For the projected Chinese PV fleet of 2030, this could amount to the current power demand of Austria, only from the clearer air and without investing in a single additional PV array. The current PV expansion strategy increases this effect: in 2014-2016, the PV capacity in northwestern China, where skies are still relatively clear, doubled–already a remarkable expansion pace–but in the eastern provinces, where many of the most polluted regions and thus the haziest skies are found, it increased four-fold. This emphasizes the need for pollution control: the highest emissions occur in places where the bulk of the PV fleet is located and where capacity increases fastest. This is also where most people live and where pollution control will have the largest impact on health.

The Chinese government has made improving air quality a priority on its agenda for the upcoming years. Our results suggest that there are large economic benefits of doing so, especially if pollution control occurs in all sectors and all pollutants are included. As the magnitude of surface solar irradiance changes depends non-linearly on emission reductions, the stronger the emission reductions–multiple sectors together and stringent regulations in all–the larger the increase on solar power generation. The energy sector, which has seen the strongest emission policies in the past, may be the easiest to de-pollute, and it is directly affected by the revenue increases we identify here. Energy companies must bear the costs of pollution control in their power stations, and energy companies–potentially the same companies–will be the ones benefitting from the increased solar generation due to the cleaner air, providing the government with economic arguments for rapidly pushing ahead in the energy sector. Overall, urgent action is needed to clear the air in China, primarily because of the health impacts of air pollution, and we have shown that the side-effect of increased solar power generation would offset a sizeable share of the costs of air pollution control measures.

CHAPTER 3. Contribution II: Cost and transmission requirements for reliable solar electricity from deserts in China and the United States

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Abstract

Concentrating solar power (CSP) with thermal storage can help integrate the increasing amounts of intermittent renewables in China and the United States. An interconnected fleet of CSP stations in the deserts of China and the United States can supply fully dispatchable or baseload electricity for the demand centers, via long-distance HVDC lines. In China the solar power cost at the point of delivery is at or below 20 cents per kWh, if the CSP fleet utilizes the solar resources in Tibet. In the United States regional weather patterns make it economically unfeasible, although technically possible, to generate fully dispatchable CSP.

1.1. Introduction

China and the United States are the world's largest energy consumers and together account for about 40% of global greenhouse gas emissions (IEA, 2014a; WRI, 2015). Whereas the United States energy demand and emissions are very high, in total and per capita, the Chinese energy demand and emissions are both high and rapidly increasing: both have increased by around 150% in the last decade (EIA, 2015b; JRC, 2015). Hence, the Chinese and American energy policy choices will have enormous influence on the world's capabilities to limit climate change. In 2014, the two countries together committed to climate change and clean energy targets: the United States commits to reduce its greenhouse gas emissions by 26–28% by 2025 compared to 2005, whereas China will peak its emissions and increase the share of non-fossil energy to 20% by 2030 (The White House, 2014). Hence, for the first time, the world's two largest economies, energy consumers and GHG emitters have credibly committed to serious action against climate change.

Currently, the two countries are the world leaders in renewable power: in 2013, the United States had 93 GW of renewables (excluding hydropower), whereas China had 118 GW renewables installed (REN21, 2014). In the United States, renewables generated some 13% of all electricity in 2014 (7% excluding hydro), after seeing a 10-fold increase in wind power generation over the last decade. Still, the United States bases its electricity supply on coal (40%) and gas power (27%) (EIA, 2015a). In China, renewables (including hydro) surpassed 20% of electricity generation in 2013, and new renewables installations exceeded the installation rate of nuclear and fossil power (REN21, 2014). Reaching its 2014 renewables pledge will require China to build 800–1,000 GW of new, mainly renewable, generation capacity–to be compared to the 560 GW renewable electricity (excluding hydro) in place globally in 2013 (REN21, 2014; The White House, 2014). Today, an 800 GW coal power fleet supplies 3/4 of the Chinese electricity supply, greatly contributing to dramatic air pollution in the large cities (IEA, 2014a). In China as in the United States, replacing this fossil power will require baseload (constant output throughout the year), or at least dispatchable, clean capacities to come online, but so far, in both countries, the lion's share of new renewable capacity is wind and solar photovoltaics power, both of which are intermittent and hence a potential threat to system stability.

Both China and the United States are dedicating significant efforts to safely integrate increasing amounts of intermittent renewables. Measures to smooth or balance intermittent resources include enlarging the grid by expanding interconnections, improving demand-side flexibility and increasing the share of controllable power such as hydropower, biomass or CSP in the generation portfolio (Patt *et al.*, 2011). Renewable power has a low power density and needs vast areas of land, which is problematic both due to cost reasons and due to land-use conflicts, in particular with agriculture. Whereas the potential for a sustainable expansion of hydropower is limited in both countries, and a large-scale expansion of biomass electricity may compete with both food and biofuel production, CSP is particularly suited for desert regions, with high levels of direct normal solar irradiance and low air moisture content. As deserts are also sparsely inhabited and the land has rather low levels of biodiversity and limited productive use for agriculture, the land-use competition for CSP is small. However, the large cities and demand centers are located far away from the desert regions, as deserts are highly inhospitable places for settlements. Hence, expanding CSP in deserts requires very long-distance transmission lines to the centers of demand.

In this article, therefore, we examine the possibility for fleets of CSP stations to deliver controllable and base load power from the deserts to the centers of demand in China and the United States. For this, we identify the generation sites, the optimal fleet compositions and the optimal transmission corridors for long-distance transmission. Finally, we calculate the cost of the electricity at the points of demand for baseload and perfectly dispatchable CSP following the demand curves of the regions the power is delivered to.

1.2. Background

Concentrating solar power in China and the United States

Concentrating solar power is an emerging technology, and installation rates remain modest: in 2013, the global CSP capacity was 3.4 GW, almost all of it in Spain and California, whereas PV reached 139 GW (REN21, 2014). It is more expensive than wind power and solar photovoltaics, but it has one feature that makes it potentially attractive–the possibility to equip it with thermal storage and allow for continuous power generation after sundown or during periods of adverse weather. A recent study shows that an interconnected and coordinated fleet of CSP stations equipped with thermal storage can supply fully dispatchable and even base load power (Pfenninger *et al.*, 2014a). Hence, CSP is renewable, controllable and can be made baseload capable, and can thus complement and balance the fluctuating supply of other renewable generation technologies, making it a potentially highly valuable option for the future renewable power systems (IPCC, 2011; Lilliestam, 2014; Trieb, 2006; Trieb *et al.*, 2014; Trieb *et al.*, 2015), in China, the United States and around the world.

In its 12th Five Year Plan (2011-2015), China has defined a target of 1,000 MW of installed capacity for CSP capacity by 2015, and 3,000 MW by 2020. Today, China's operational CSP capacity is very low, but some 2,400 MW have been announced or are under development, in part under a feed-in tariff scheme currently set at 19.2 cents per kWh (IRENA, 2014b). The United States, in contrast, has 1,400 MW CSP capacity installed (mid-2014) and another 1,000 MW under construction (REN21, 2014).

Both China and the United States have deserts with considerable CSP potentials within their borders. This gives them an advantage over Europe, on which most CSP research has focused in the past although its largest CSP resource lies outside its borders in the Saharan and Arab deserts. The solar resource potential in China is mainly located in the desert region in the West of the country, far away from the megacities on the East coast, where most of the electricity is consumed. This is similar in the United States, where the best solar resources are located in the desert region of the Southwest, and most demand centers are located on the East and West coasts. As the potential solar sites and the demand centers are far apart, electricity from CSP must be transported over long distances, often over 1,000–2,000 km or more. Depending on the distance, high-voltage alternating current (HVAC) lines are more suited for links up to 800 km, whereas high-voltage direct current (HVDC) lines are more suited for longer distances, because of their lower losses and higher capacity per line. The transmission costs, even over such vast distances, typically only add few cents per kWh to total cost, so that the levelised cost of transmission is rarely a significant obstacle to CSP (Trieb *et al.*, 2012).

Grid expansion and experiences with point-to-point HVDC

China

The Chinese power system has six regional power clusters: the North, Northeast, Northwest, Central, Eastern and the Southern regions (IRENA, 2014b). The clusters are interconnected, but even the large infrastructure investments of the last decade have not been sufficient to keep pace with the very rapid demand increase, so that there are considerable bottlenecks between the regions. Consequentially, only a few percent of the electricity is traded across regions (IEA, 2011; IRENA, 2014b). Both renewable electricity and grid interconnections have been a focus of the Five-Year Plans since 2000, with the particular aim to bring investment and development to China's lagging West while meeting the increasing electricity needs of the Eastern provinces. Since 2011, renewables are classified as a strategic industry and the government has defined national targets for renewables (IRENA, 2014b). As a consequence of these plans, China is constructing three electricity transmission corridors to connect new generation capacity in the Northern, Central and Southern provinces to the demand centers in Beijing, Tianjin, Hebei, Shanghai, Zhejiang, Jiangsu, and Guangdong:

- The Northern Corridor connects hydropower stations on the Yellow River and coal bases in the north to Hebei Province and the two big cities Beijing and Tianjin;
- The Central Corridor connects hydropower plants in the upper Yangtze River (and will include resources in Tibet by 2020) to the Yangtze River Delta (YRD) mega-region. The Three Gorges Dam is fundamental to this corridor, sending 35% of its electricity to the YRD;
- The Southern Corridor sends electricity to China's manufacturing hub in Guangdong from new coal bases and hydropower plants in the south. The Three Gorges Dam also sends electricity to the southern corridor.

For these corridors, China has embarked on a program to construct dedicated point-to-point long-distance HVDC. Each of the corridors is expected to exceed 40 GW in capacity by 2020 (Wilson Center, 2015)–a combined capacity equivalent to 60 Hoover Dams. Over the last 5 years, China has completed 30 GW of HVDC lines, each of them exceeding 2,000 km length, including the 2,200 km 8 GW Hami-Zhengzhou and the 2,100 km 7.2 GW Jinping-Sunan HVDC lines commissioned in 2014 and 2012, respectively (IRENA, 2014b; Trieb *et al.*, 2015). The large electricity projects in China are based on coal and hydropower, and increasingly on wind, and the very long-distance transmission to the coastal demand centers go via dedicated point-to-point HVDC lines. Exactly the same approach could be used to transport sustainable and dispatchable CSP to the megacities: this, in fact, is exactly what we investigate in the paper.

United States

The United States transmission system is the emergent result of local utilities to connect cities to adjacent fossil fuels plants. Today, the United States power system is split into three largely isolated systems–the Eastern, Western and Texas Interconnections. The Interconnections are connected through DC links, allowing for limited power exchange among them. There is no national target for renewables, nor a national strategy for the development of the power mix, but all such matters are handled at the state level (EIA, 2012). Hence, there are considerable differences in power mixes between Interconnections and also between the power pools within each Interconnection, but all of them are strongly based on coal and gas power (EIA, 2015a).

Within the Interconnections, there is much experience with point-to-point HVDC links. In the West, for example, the 3,100 MW and 1,400 km long Pacific HVDC Intertie line transmits hydroelectricity from the Pacific Northwest to Los Angeles along a distance of 1,400 km (ABB, 2015b). Similarly, the Intermountain HVDC line transports 2,400 MW coal power over 800 km from Utah to Los Angeles; these two lines together serve about 1/3 of the households in Los Angeles (ABB, 2015a). In the East, the 2 GW and 1,500 km long Quebec-New England HVDC line, one of two multi-terminal HVDC systems in the world, transports hydropower from Quebec to Montreal and Boston (ABB, 2015c). Other than in China, HVDC expansion plans in the United States are not driven by increasing demand, but rather by a desire to increase interconnectivity and expand and safely integrate renewables (Clean Line, 2015), especially wind power. Current proposals include:

- The 1,300 km Grain Belt Express, which is to connect the wind resources of Kansas to Missouri, Illinois, Indiana and markets further east;
- The 3.5 GW 1,100 km Plains & Eastern transmission line, which will transport wind power from Oklahoma, Kansas, and the Texas Panhandle to Tennessee, Arkansas, and other markets in the Mid-South and Southeast;
- The 800 km and 3.5 GW Rock Island line, which is expected to transport wind power from Iowa to Illinois and other states further east.

Hence, the United States has experience with long-distance HVDC transmission of remote coal and hydropower (and in the future, possibly wind power) to the demand centers, in schemes similar to the CSP projects we examine here.

1.3. Methodology

We assess the possibilities for and costs of dispatchable and baseload CSP supplied to the demand centers of China and the United States using a four-step model using hourly solar irradiance and weather patterns, highly resolved terrain data and hourly demand curves for the supplied regions.

First, we identify potential desert generation sites. For this, we identify the areas with the highest levels of direct normal irradiance, which is the key determinant of CSP generation costs (Trieb *et al.*, 2012). We use long-term annual irradiance average data, and highly spatially resolved data (for China 0.05°x0.05° covering the period 1999-2005/2007-2013 (Amillo *et al.*, 2014), and for the United States 0.1°x0.1° covering the period 1998-2009 (NREL)). We exclude all land with direct normal irradiance levels below 2,000 kWh/m^2/year. As CSP utilizes only direct light, cloud cover greatly reduces the heat collection, and ultimately the electricity generation. To reduce the impact of local weather phenomena and reduce the weather correlation between sites, we maximize the geographical spread between the sites with the highest direct normal irradiance. For China, we consider a) only the best solar sites, which are located in Tibet and b) only the best solar sites outside Tibet, which China may want to leave aside for political reasons; these resources are found in Qinghai. For the United States, we limit the potential sites to a) the current and planned CSP sites and b) among all suitable CSP sites, also in areas not presently considered for expansion. We then apply geographical restrictions to land to reduce impact on biodiversity, soils and land-use and land-cover change to install the solar plants. We exclude unsuited terrain, such as hard pans, forest, cropland, wet lands, water bodies, glaciers and settlements (Bingfang *et al.*, 2003; Latifovic *et al.*, 2003), all protected areas (UNEP-WCMC and IUCN, 2010b) and terrain with slope exceeding 2.1% (Fischer *et al.*, 2008; Kronsgae, 2001). We assume dry-cooled CSP tower stations, so that water availability does not limit the site selection (Damerau *et al.*, 2011).

Second, we optimize the plant siting, design and operation of the entire plant fleet, so as to fully meet the actual hourly demand curves of the demand centers, or to produce baseload power. This includes the costs for intra-fleet transmission, for which each plant is connected to two others to make the fleet n-1 secure. For the plants at existing sites in the United States, we assume the CSP stations to be in a copper plate, as these sites are already interconnected via the AC grid, so in this specific case we model no intra-fleet transmission. The analysis is performed with *Calliope*, a linear programming model for spatial-temporal energy system cost optimization (Pfenninger *et al.*, 2014c; Pfenninger and Keirstead, 2015). *Calliope* simulates the behavior of a CSP plant in each of the selected pixels, and optimizes the size of the solar field, thermal storage and power block, excluding sites that are not needed. The objective function is to minimize system cost, so the results provide the most techno-economically feasible system given the input constraints, which in our case are the geographical exclusion factors, the irradiance level, the construction and operation costs and the two types of demand curves. *Calliope* calculates the minimized costs for meeting all demand using the CSP fleets. For both countries, we use hourly resolved irradiance data, and highly spatially resolved data (for China 0.05°x0.05° (Amillo *et al.*, 2014), and for the United States 0.038°x0.038° (Sengupta *et al.*, 2014)). The construction and O&M costs for a solar tower plant are from Turchi and Heath (2013).

For China, we use the 2013 hourly demand data for six grid areas (we have no data for the autonomous provincial power network of Tibet) (Bai *et al.*, 2013; IRENA, 2014b; Xiaotao, 2014). The northern, northeastern and northwestern areas have winter peak demand and the central, eastern and southern grids have a larger summer peak demand. For the United States, we use 2014 hourly demand data for six grid areas supplying some of the largest United States metropolitan areas (the California ISO, the Southwest Power pool, Texas (ERCOT), New England ISO, Midcontinent ISO and the PJM Interconnection). All the grid areas had usually a summer peak demand. For both countries, the demand curves are scaled so that the peak load is lower than the maximum CSP capacity (maximum number of generation sites times maximum capacity per site times number of sites). The maximum size of the solar field per site is determined by the size of each solar data pixel; for both countries, we assume the same capacity-to-area ration as in Ivanpah, (NREL, 2014), which is currently the world's largest solar tower station. To satisfy a real, higher demand, the number of plants would have to scale up accordingly.

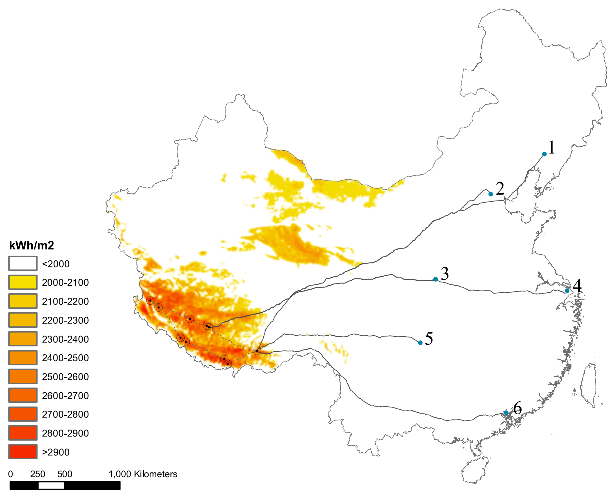
Third, we identify the optimal transmission routes from the fleet to the demand centers, using a GIS algorithm to minimize economic, social and environmental costs. This GIS algorithm relies on a weighting approach based on relative costs, also called friction costs, which are assigned to each land pixel to weight its relative suitability for line construction. Friction cost parameters are divided into isotropic and anisotropic gridded data. Isotropic gridded data have the same value in all directions, as land cover typology, whereas anisotropic data contains data in a specific direction such the *z* axis, as the slope of the terrain. We assign a value of 1.0 for the base cost value of the friction image up to a value of 10.0 depending on the typology of land; we assign base costs for grassland and bush land–making them the most attractive terrains to build in–and increase costs to land with highest ecological value such as protected forests. For building in hilly or mountainous areas, where the slope makes construction laborious, we assume friction costs of 1.0 for slopes up to 20% and range the slope in steps of 45% up to a friction factor of 10.0 equivalent to slopes of 200% or higher. For intra-fleet transmission, we model HVAC lines connecting the plants of the fleet. For the long-distance transmission, we model HVDC links from the fleet to the demand centers so as to achieve the least-cost configuration. All transmission cost data are from Parsons Brinckerhoff (2012) and Black&Veatch (2014).

Fourth, we add the levelized generation (including intra-fleet transmission) and long-distance HVDC transmission cost to the total levelized cost of electricity (LEC) at the point of delivery in each of the demand centers. Cost figures are in $\$_{2012}$ cents.

1.4. Results and Discussion

China

In the Chinese scenarios, we examine CSP production and transmission from a) Tibet and b) Qinghai to the demand centers further east. In the Tibet scenario, which utilizes only very good CSP sites with an average direct normal irradiance of 2,654 kWh/m^2/year, an irradiance level similar to the one in northern Africa, the costs are relatively low. The result of the optimized fleet and transmission siting, design and operation (see Figure 1) shows that a fleet of CSP plants located in Tibet is capable of supplying fully dispatchable power, fully following the demand curve of the six demand regions, and also to supply baseload electricity. The costs at the point of demand are 19–20 cents per kWh, both to follow a demand curve and supply baseload. The HVDC transmission lines are very long, ranging from 1,700 km (Tibet-Chongqing) to 3,800 km (Tibet-Shenyang).

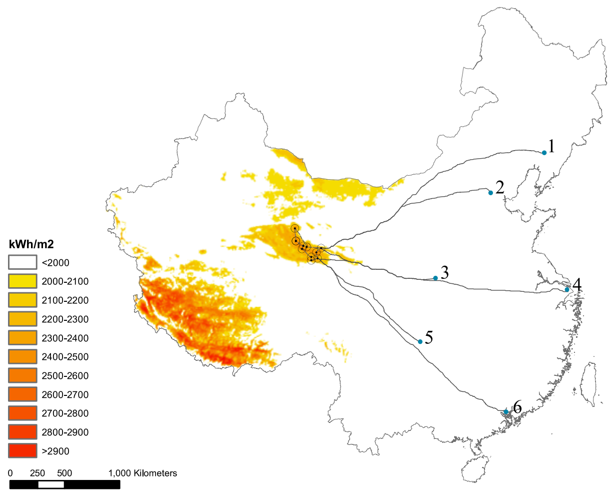


Demand following LEC cents per kWh
[1] Shenyang: 20
[2] Beijing: 20
[3] Xi'an: 20
[4] Shanghai: 20
[5] Chongqing: 19
[6] Guangzhou: 20

Baseload LEC cents per kWh
[1] Shenyang: 20
[2] Beijing: 20
[3] Xi'an: 20
[4] Shanghai: 20
[5] Chongqing: 20
[6] Guangzhou: 20

Figure 1 Levelized electricity cost at point of demand for China when supplied by a CSP fleet in Tibet.

The second scenario examines a fleet of CSP stations in Qinghai (see Figure 2), without utilizing the resources in Tibet. The Qinghai average direct normal irradiance level of the sites selected here is 2,132 kWh/m^2/year, an irradiance level similar to southern Spain. A fleet of plants located in Qinghai can follow the demand curve of the six regions at 32 cents per kWh and supply baseload at 33-34 cents per kWh. Relying solely on the power supply from Qinghai thus increases the costs by 60–70% compared to the Tibetan scenario. The transmission lines, however, are considerably much shorter than in the Tibetan scenario and are comparable in length to those already constructed in China, ranging from 1,200 km (Qinghai-Xi'an) to 2,500 km (Qinghai-Shenyang). In both scenarios, the transmission infrastructure adds 1–2 cents per kWh to the generation cost, corresponding to less than 7% of the total cost at the points of delivery.



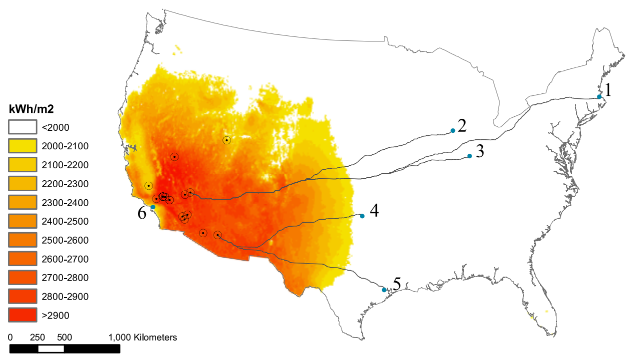
Demand following LEC cents per kWh
[1] Shenyang: 32
[2] Beijing: 32
[3] Xi'an: 32
[4] Shanghai: 32
[5] Chongqing: 32
[6] Guangzhou: 32

Baseload LEC cents per kWh
[1] Shenyang: 34
[2] Beijing: 33
[3] Xi'an: 33
[4] Shanghai: 33
[5] Chongqing: 33
[6] Guangzhou: 33

Figure 2 Levelized electricity cost at point of demand for China when supplied by a CSP fleet in Qinghai.

United States

In the first scenario for the United States, we limit the set of possible generation sites to those where a CSP plant has already been constructed, or where one is under construction or in planning phase (see Figure 3). The annual average direct normal irradiance level of these sites is 2,506 kWh/m^2/year. A fleet of plants located on a subset of these sites is capable to follow the demand curves of the six power regions at costs of 39–41 cents per kWh, and to supply baseload at 41–42 cents per kWh. The transmission lines are long, ranging from 1,700 km (Southwestern deserts-Houston) to 4,200 km (Southwestern deserts-Boston). As California has CSP plants already installed that are supplying power to the grid, we assume that no additional HVDC lines transmission was for supplying Los Angeles.

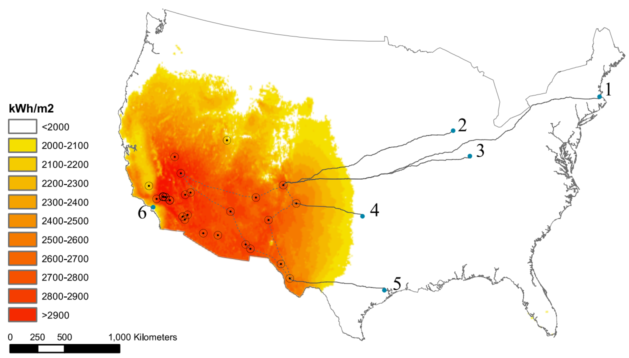


Demand following LEC cents per kWh
[1] Boston: 39
[2] Chicago: 40
[3] Indianapolis: 41
[4] Oklahoma City: 40
[5] Houston: 40
[6] Los Angeles: 40

Baseload LEC cents per kWh
[1] Boston: 41
[2] Chicago: 41
[3] Indianapolis: 42
[4] Oklahoma City: 42
[5] Houston: 42
[6] Los Angeles: 41

Figure 3 Levelized electricity cost at point of demand for the United States when supplied by a CSP fleet at existing/planned sites.

In the second scenario, we do not limit the potential sites but choose from all possible generation sites with a high direct normal irradiance (see Figure 4). These new solar sites are located in the state of Nevada, Arizona, Colorado, New Mexico and Texas. The annual average direct normal irradiance of all sites is 2,504 kWh/m^2/year, which is practically identical to the previous scenario. Moreover, in this case, it is possible to generate baseload and to fully follow the demand curves of the supplied regions, but the costs are high: 37–38 cents per kWh for demand following and 39–40 cents per kWh for baseload. Hence, the larger supply area reduces costs by 5% compared to the first scenario. As the generation area is larger, the HVDC links are shorter than in the first scenario, ranging from 900 km (Southwest-Houston) to 3,300 km (Southwest-Boston); moreover, here we assume that no additional HVDC line is necessary to supply Los Angeles. In both scenarios, the transmission infrastructure adds 1–2 cents per kWh to the generation cost, corresponding to less than 6% of the total cost at the point of delivery.



Demand following LEC cents per kWh
[1] Boston: 37
[2] Chicago: 37
[3] Indianapolis: 38
[4] Oklahoma City: 38
[5] Houston: 38
[6] Los Angeles: 37

Baseload LEC cents per kWh
[1] Boston: 39
[2] Chicago: 39
[3] Indianapolis: 40
[4] Oklahoma City: 39
[5] Houston: 39
[6] Los Angeles: 39

Figure 4 Levelized electricity cost at point of demand for the United States when supplied by a CSP fleet at all suitable sites

An interconnected and coordinated fleet of CSP stations equipped with thermal storage can provide fully dispatchable and load-following renewable electricity, and even baseload power, to the centers of demand in both countries. The costs of doing so are well within the existing feed-in tariff for CSP in China, at around 19.2 cents per kWh, but it is much more expensive and not competitive in the United States, mainly because of the North American Monsoon.

For China, generating CSP in a fleet of plants in Tibet is the most attractive configuration from a cost perspective: excluding Tibet and utilizing only the Qinghai solar resource is 60–70% more expensive than a Tibet-based supply system, although the power lines are shorter. Hence, there may be political reasons to not base a part of the future electricity supply of China on Tibetan resources and, indeed, the first large CSP project is not in Tibet but in Qinghai (IRENA, 2014b). Doing so at scale, for an entire fleet of CSP stations, would however come at a high economic cost. We have however shown that both baseload and load following are economically feasible, despite the long transmission lines required, if the supply is based in Tibet.

For the United States, it makes little difference in terms of cost if a future CSP fleet is located where projects are planned or over a larger area: the solar resource is equally good over vast areas in the Southwest. Generating CSP over a larger area has minor (~5%) cost advantages, mainly located to the lower correlation of local weather patterns, but even the broadest feasible geographical expanse does not cancel out the effects of the monsoon, which affects the entire region. Thus, posing an extreme availability constraint on CSP–here, we assume 100% baseload or demand following–is not economically feasible. Previous research has however shown that relaxing this requirement to 70% or 80% baseload capability or load following, comparable to what most fossil power plants bring, reduces the generation cost to a more reasonable 15–18 cents per kWh (Pfenninger *et al.*, 2014a).

In the future, the need for electricity that is both renewable and dispatchable will grow, as higher and higher shares of intermittent renewables feed in to the grids of China, the United States and other systems around the world. Fully dispatchable solar power from CSP fleets in the deserts is not, and may never become, the cheapest option, but it may become necessary solutions to the reliability problems ahead. However, the access to this resource is dependent on long–sometimes very long–transmission lines from the deserts to the centers of demand. Deployment of intra-fleet networks and long point-to-point lines does not affect significantly the overall levelized cost, but it does greatly increase the complexity of the project. The deployment of point-to-point lines across states and regions may require for significant intra-state cooperation, especially in the United States, where the permitting and construction of a power line is often a lengthy process. Yet, a CSP expansion in the United States and China have a considerable advantage compared to Europe, which would require not only multi-level decision making within their own country but also among several exporter, transit and importer countries. It thus appears that the main challenge to supply fully dispatchable solar power to the demand centers in China and the United States is not technical or economical, but political, requiring coordinated policy action among states and policy levels to facilitate the deployment of such long-distance transmission. Still, exactly the type of HVDC links we discuss here exist in both countries: China has a large experience deploying long-distance and very high-capacity HVDC transmission lines in the last 5 years, and similar HVDC links have been in use in the United States for decades. Although these schemes transport mainly coal and hydropower, this provides a proof of concept that, although challenging, such CSP and point-to-point long-distance transmission schemes are technically possible as well as economically and politically feasible.

1.5. Conclusions

We have shown that an interconnected fleet of CSP stations in the deserts of China and the United States can supply fully dispatchable or baseload electricity for the growing demand centers. In China, the cost of such solar power at the point of delivery in the large cities is reasonable, at or below 20 cents per kWh, if the CSP fleet utilizes the excellent solar resources in Tibet. Basing the CSP supply on non-Tibetan resources, which may or may not be politically attractive and avoid longer-term political tension between the central government and Tibet, is possible, but it is an economically costly solution. In the United States, it is technically possible but not economically feasible to require the CSP generation to be fully dispatchable due to the presence of the North American Monsoon, which creates adverse weather over vast areas during late summer. Relaxing the availability constraint to similar levels as fossil fuel power plants bring, would make an interconnected CSP fleet economically attractive. In both countries, the very long HVDC lines add complexity to a large-scale CSP expansion, although it hardly adds to the levelized cost at the point of delivery. Simultaneously, both countries have experience with large-scale power transmission via dedicated point-to-point HVDC lines over large distances, in schemes similar to the one we investigate here, providing proof-of-principle that such solutions are technically possible as well as economically and politically doable.

CHAPTER 4. Contribution III: Impact of political and economic barriers for concentrating solar power in Sub-Saharan Africa

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Abstract

Sub-Saharan Africa (SSA) needs additional affordable and reliable electricity to fuel its social and economic development. Ideally, all of this new supply is carbon-neutral. The potentials for renewables in SSA suffice for any conceivable demand, but the wind power and photovoltaic resources are intermittent and difficult to integrate in the weak electricity grids. Here, we investigate the potential for supplying SSA demand centers with dispatchable electricity from concentrating solar power (CSP) stations equipped with thermal storage. We show that, given anticipated cost reductions from technological improvements, power from CSP could be competitive with coal power in Southern Africa by 2025; but in most SSA countries, power from CSP may not be competitive. We also show that variations in risk across countries influences the cost of power from CSP more than variations in solar resources. If policies to de-risk CSP investment to financing cost levels found in industrialized countries were successfully implemented, power from CSP could become cheaper than coal power by 2025 in all SSA countries. Policies to increase institutional capacity and cooperation among SSA countries could reduce costs further. With dedicated policy measures, therefore, CSP could become an economically attractive electricity option for all SSA countries.

1.1. Introduction

The electricity systems of Sub-Saharan Africa (SSA) face a number of serious challenges. Electricity demand is increasing rapidly, and is likely to at least double in the next 25 years (EIA, 2013; IRENA, 2015a). Simultaneously, only one-third of the population has electricity access, and current progress on electrification is merely keeping up with the population growth (IEA and World Bank, 2015). There is thus a need to expand the electricity generation faster than today: need estimates range from 7,000 MW/year to 14,000 MW/year, corresponding to 5–10% of the currently installed capacity; presently, some 4,000 MW/year are installed in SSA (EIA, 2015d). Blackouts are common because of capacity shortages and unreliable infrastructure, forcing consumers to rely on expensive and inefficient diesel-fueled backup generators. In some countries, diesel generators represent half the installed capacity, despite their very high cost of 50 cents per kWh or more, greatly exceeding the cost of grid power (Briceño-Garmendia and Shkaratan, 2011; Eberhard *et al.*, 2011; Eberhard and Shkaratan, 2012; Gallup, 2010; Mukasa *et al.*, 2015).

The electricity production must be completely decarbonized by the second half of this century, also in SSA (IPCC, 2014; UNFCCC, 2015a). This means that all new long-lived infrastructure must be based on carbon-neutral technologies (IPCC, 2011; Rogelj *et al.*, 2015). To meet the objectives of sustainable development and poverty eradication defined under the Millennium Development Goals (MDGs) and the Paris Agreement (UN, 2016; UNFCCC, 2015a), however, new electricity generation in SSA also needs to be affordable, not increasing costs beyond what consumers can afford. Currently, three-quarters of the sub-Saharan countries have average power generation costs exceeding 10 cents per kWh, and one third exceed 15 cents per kWh (Eberhard *et al.*, 2011). Hence, if new carbon-neutral electricity is to be considered "affordable", it must be at least competitive with the existing power mix and have generation costs of less than 10–15 cents per kWh. If it is to be competitive with the largest electricity system carbon emitter–coal power–then it must have generation costs of less than about 8 cents per kWh (IRENA, 2013c).

In the sub-Saharan context, the search for additional generation is further complicated, as the weak electricity grids south of the Sahara would struggle to integrate large-scale additions of new intermittent power (Mukasa *et al.*, 2015). Hence, either the grids must be reinforced to integrate fluctuating renewables, or ways could be sought to smooth the renewable electricity on the generation site and make the feed-in predictable and controllable so as to minimize the added strain on the grid. Dispatchable and economical renewable power would therefore be particularly valuable for the electricity supply of SSA.

These multiple policy objectives of carbon-neutrality, dispatchability and affordability are not easily compatible, for several reasons. Current costs of renewable power still exceed those of most fossil technologies, although this gap has closed substantially through substantial technological development: the cost of solar photovoltaics, for example, has decreased by 50% over the last four years (IPCC, 2011, 2014; Rogelj *et al.*, 2015). Solar photovoltaics and wind turbines are the least-cost renewable technologies, and both could be competitive on a levelized cost basis in many SSA countries: today, wind power costs some 6–9 cents per kWh, on par with new fossil generation, while PV costs some 10–12 cents per kWh in America and Europe, depending on solar resource and market situation, down to 6 cents per kWh in the United Arab Emirates with very good solar resources (IRENA, 2015b). On the other hand, there are not many options for supplying dispatchable renewable power at large scale. Dam hydropower and biomass power have limited potentials and are questionable for a very large-scale expansion because of their environmental impact (IRENA, 2012c, 2014a). Wind power would need bulk storage for large amounts of power, such as pressurized air storage, to smooth the wind farm output on-site, and such storages are currently not commercially available at scale (Budt *et al.*, 2016). Solar photovoltaics, which is modular and easy to quickly install also in remote places, can be equipped with batteries in a decentralized setting, making the supply to the grid more or even fully predictable, or enabling consumers to be fully autarkic (Baurzhan and Jenkins, 2016). The last option–the one we investigate here–is concentrating solar power (CSP) with thermal storage, which offers the potential to provide fully predictable renewable bulk power (Pfenninger *et al.*, 2014a). The potential for CSP in SSA is vast, and would in principle suffice to cover any conceivable future SSA demand (Hermann *et al.*, 2014; Trieb *et al.*, 2009b). However, CSP is lagging behind and is not expanded as fast as photovoltaics –there are 5 GW of CSP world-wide, compared to 230 GW photovoltaics (NREL, 2016; SolarPowerEurope, 2014), also because of photovoltaics' rapid cost development. Indeed, several projects have seen a shift in technology, from CSP to photovoltaics, because of the lower costs of PV. For example, this happened at the 250 MW Beacon project in the United States (CSP World, 2013) and the 10–30 MW Erfoud, Zagora and Missour projects in Morocco (World Bank, 2014a): in these cases, the CSP plants were planned without storage, so that the CSP power would have been similarly fluctuating as that of the final photovoltaics projects. Today, most recent CSP projects and those under construction are equipped with thermal storage to leverage this advantage, including all CSP stations built or under construction in Africa (Morocco and South Africa) (NREL, 2016). When comparing CSP with thermal storage and photovoltaics with lithium-ion (Li-ion) batteries on a levelized cost of electricity (LCOE) basis, CSP with storage emerges as the lower-cost alternative: using current and projected costs (2020), the LCOE of CSP is lower than of PV with the same hours of storage for peak and intermediate power coverage (Feldman *et al.*, 2016). When comparing CSP with thermal storage and photovoltaics with Li-ion batteries on a net system cost basis, the projected costs (2020) of both technologies are similar but with high uncertainties especially for photovoltaics with batteries (Mehos *et al.*, 2016).

Here, therefore, we examine the competitiveness of CSP with thermal storage as one possible policy option for supplying dispatchable renewable power to SSA and compare it with typical cost of coal power, which in most cases is the currently cheapest dispatchable electricity supply option. In this article, we investigate the potential for and cost of CSP with thermal storage in SSA. In particular, we explore how dispatchable solar power could be traded, and investigate how the current political, institutional and economic situation in SSA with its far-reaching effects on financing costs, technological capacity, and international cooperation on infrastructure development affect the prospects of this technology, and what it would take in terms of policy to solve key problems and make CSP with thermal storage a viable electricity option in SSA.

1.2. Background

Concentrating solar power

Concentrating solar power collects the heat of the sun through large mirrors, which focus the light on a focal line (parabolic trough, Fresnel) or a focal point (solar towers), to generate steam and drive a turbine. The aspect that sets CSP off from other renewables is the option of equipping it with thermal storage. The thermal storage is charged during the sunny hours of the day and allows the power station to operate after sundown, at night, or during periods of adverse weather. Recent analysis suggests that with the proper system coordination, CSP with thermal storage can be operated in the Northern and Southern African deserts to provide both a constant and a dispatchable power supply (Pfenninger *et al.*, 2014a; Trieb *et al.*, 2014).

Today, there are almost 5 GW of CSP in the world, mainly in Spain and in the United States, and further CSP stations stand in another 8 countries, including South Africa, Morocco, China and India. This is less than expected during the CSP hype a decade ago, but CSP continues to develop and expand, albeit at a much slower pace than wind and solar photovoltaics. Some 2 GW of CSP are currently under construction, almost all of which outside the industrialized world, mainly in Morocco, South Africa, Chile, China, and India (NREL, 2016).

One reason for the slow expansion pace is that optimal conditions for CSP are found in areas with high direct normal solar irradiance. Such areas are typically found in deserts and arid regions, and most deserts are not in the industrialized countries traditionally driving renewables development and expansion (IRENA, 2012b; Lilliestam *et al.*, 2012). Even in countries with good CSP sites, such as the United States or South Africa, large cities and densely populated areas are often located far away from such dry places, so that long power lines are needed for CSP to reach the main grid and the consumers. This makes CSP projects more complicated than renewables to be expanded near demand, but CSP projects can be cost-effectively connected to demand-centers with high-voltage power lines (Trieb *et al.*, 2015).

Renewable energy investments and finance in Sub-Saharan Africa

Renewable power technologies have high upfront investment costs but low operation costs compared to fossil alternatives, as they have no fuel costs–except biomass power. The investment and the financing costs[4] are therefore the dominant drivers of the LCOE for renewables, making them very different investment cases than, for example, gas and coal power stations.

Investment costs are commonly higher in developing than in developed countries due to factors such as poorly trained labor forces, a need to bring engineers from abroad, and weak transportation infrastructure (IRENA, 2015a; Ondraczek *et al.*, 2015). The financing costs are also commonly much higher in developing than in developed countries, as they represent the extra reward required by investors and lenders to compensate them for the high risks. These risks arise because of perceived or factual political, regulatory, financial and administrative barriers, long and uncertain permission processes, and other general investment risks (Backhaus *et al.*, 2015; Ondraczek *et al.*, 2015; UNDP, 2013). Given that renewables are capital-intense investments, renewable energy projects are especially sensitive to financing risks driving up the cost of capital (Williges *et al.*, 2010). To address this, international efforts are underway to lower such barriers and help improving legal, policy and regulatory environments to decrease such risks and facilitate renewable energy investments, for example in the US-led Power Africa initiative but also within the frame of the Paris Agreement (UNFCCC, 2015a; US Government-led Partnership, 2015).

To our knowledge, only few renewable energy studies consider differences in financing risk and use country-specific financing costs. In the cases where this is done, for example for solar photovoltaics in Peters *et al.* (2011) and photovoltaics and wind power in Schmidt *et al.* (2012), the importance of contextualization by taking country risk into account is a key finding. For example, Schinko and Komendantova (2016) show that the actual weighted average cost of capital (WACC) in North Africa is more than twice as high as in Europe, and policies bringing the North African WACC down to European levels could decrease CSP costs by 40%. Even more striking, Ondraczek *et al.* (2015) show by applying a country-specific WACC to solar photovoltaics in all countries globally that the WACC is a stronger determinant for the PV cost than the solar resource quality: counter-intuitively, they show that it is cheaper to build photovoltaics in a low-sun and low-risk country such as Germany than in a high-sun, higher-risk one such as many SSA countries.

Despite its importance for renewable LCOE and its large variance across countries, most studies assume uniform financing costs for all assessed countries. The International Renewable Energy Agency (IRENA) uses, for example, a uniform 10% discount rate when examining the prospects for renewable energy in the Southern and Western African power pools (IRENA, 2013c, d), and also globally

[4] Throughout the article, we use the terms weighted average cost of capital (WACC), financing cost and discount rate interchangeably, as they refer to practically the same financial concept in the context of our study.

(IRENA, 2013b). This standardization allows for direct comparison between projects and technologies, but also means that the risk profile of all countries is assumed to be the same, which is obviously an incorrect assumption. Here, we assume country-specific WACCs (see section 1.3).

Electricity cooperation in Sub-Saharan Africa

Sub-Saharan Africa has four regional power pools–the Central, Eastern, Western and Southern African power pools–that trade electricity among the participating countries to foster economies of scale and improve reliability of the electricity system. Some of the electricity trade is accompanied by long-distance transmission, such as the 1,400 km high-voltage direct current (HVDC) link connecting the Cahora-Bassa dam in Mozambique to Johannesburg, South Africa. Two more HVDC lines connect remote generation points in Namibia (Caprivi Link, 950 km) and Democratic Republic of the Congo (DRC) (Inga-Shaba, 1,700 km). Yet the experience with substantial international power trade and long-distance transmission remains limited: only 16% of all electricity in SSA is traded between countries, and more than 90% of this is in the Southern power pool (Eberhard *et al.*, 2011).

Previous studies have identified insufficient institutional capacity, especially for the coordination and execution of multi-national projects, as an important barrier to CSP expansion in cooperation between North Africa and Europe (Lilliestam *et al.*, 2012; Lilliestam and Patt, 2015; Williges *et al.*, 2010), along with the fact that many potential exporter countries struggle already with satisfying their own electricity needs and have difficulties to raise finance to fund large-scale generation and transmission assets for their own needs (Beneking *et al.*, 2016; Frieden *et al.*, 2016; Lilliestam *et al.*, 2016). Multi-national CSP and transmission projects may be even more challenging in the SSA context, where most countries lack the institutional capacity present in Europe and the Maghreb, putting up additional barriers compared to similar projects in other regions. Such problems vary between countries and their domestic political and economic situation, but may include administrative inefficiency, political instability, corruption, low political and institutional capacity and weak administration. None of these barriers are CSP-specific, and may also be encountered in other multi-national projects, such as gas pipelines or highways (Kaufmann and Kraay, 2016; Transparency international, 2016).

Large-scale, multi-national electricity projects will be particularly difficult to realize in countries with particularly weak or even failed institutions, in so-called *fragile states* (FFP, 2014). Fragile states are those where the governance systems have collapsed and the government is unable to maintain core functions, including having lost the state monopoly of violence or control over parts of the territory, and a failure to supply most or all of the public services. State fragility thus leads to an erosion of government legitimacy and its capacity to make and enforce decisions (DFID, 2005), so that fragile states will have great difficulties in enacting large-scale cooperation projects with other countries. For example, the Inga 3 hydropower project in DR Congo, a fragile state, exemplifies how insufficient institutional capacity and political instability may make infeasible an economically attractive project.

There are several occasions in which the DRC closed a deal to build the Inga 3 dam–most recently to South Africa, via an HVDC line through Angola and Namibia. Economically it could be attractive: the power could be cheap, and South Africa needs firm capacity; yet, just as on several other occasions since the 1950s investors have withdrawn, and there is no activity on the ground, no financing deals have been settled, and there are no plans for how or where to build the transmission line, as administration is slow and the uncertainty and risks, including financing risk, are vast (International Rivers, 2016). Currently, 10 of 49 SSA countries are classified as fragile: South Sudan, Sudan, Somalia, Central African Republic (CAR), DRC (very high alert); and Chad, Zimbabwe, Guinea, Côte d'Ivoire and Guinea Bissau (high alert) (FFP, 2014).

1.3. Methodology

Model structure

To estimate the cost of CSP stations and transmission lines and the cost for delivery to SSA demand centers, we developed a model to identify the best sites to install CSP stations and the optimal power line routes from the generation sites to selected demand centers, and calculate the total cost of CSP generation at these sites and the HVDC or HVAC transmission to the different demand centers. We describe each step of the modeling here, and a detailed description of the model, including equations, data, assumptions and sources is found in sections B1-B4 in Appendix B.

We select the demand centers among metropolitan areas with more than one million inhabitants (UN-Habitat, 2014) or among national economic centers (World Bank, 2015a). This is where the need for power is the largest today, and these are likely areas for the fastest demand growth in the future. We consider these demand centers as representatives for the country, as anchoring points for the power lines, and hence limit the selection to one city per country while seeking geographic spread between the cities. We exclude fragile states from being demand centers, and from being supply and transit countries in the base case and selected scenarios (see sections 1.3 Base case and Scenario variations).

To give a sense of magnitude, we compare our results with the typical cost of coal power, which is the currently cheapest dispatchable power option. For this benchmark, we assume that the costs of coal power are the same across the continent, which is of course not exactly correct: the costs will vary across countries, for example depending on the country-specific financing risk or the availability of domestic coal resources. Hence, the comparison is to be understood as a tool to help quickly see whether CSP with thermal storage is, under the scenario conditions, an economically attractive option for SSA countries. It is not intended as a precise statement or forecast of the cost of coal power, but as a help to the reader. We take the cost for coal power from studies of IRENA for the Southern and Eastern African power pools (IRENA, 2013c, d).

We model the cost of supplying electricity from CSP in three consecutive steps. We first identify the most suitable sites to deploy CSP stations for direct normal irradiance levels exceeding 2,000 kWh/m^2/year, a level to which typically project developers restrict the potential sites (IRENA, 2012b). We classify the generation sites according to their direct normal irradiance, in steps of 100 kWh/m^2/year. Within this large set of potential sites, we exclude areas where CSP cannot be built (e.g. too steep terrain, water bodies, protected areas, settlements, shifting sand) as detailed in Table A in Appendix B. This gives a set of possible generation sites, at different resource levels.

Second, we identify the transmission corridors from the demand centers to the generation sites, by seeking the least-cost corridor between the demand center and the closest generation site at each direct normal irradiance level. We do this by assigning weights–so-called friction costs–to different types of land, defining grassland as the base (friction cost 1) and assign equal or higher friction costs to other terrain types, for example mountains or forest. For data on this, see Table B in Appendix B. For distances exceeding 800 km, we simulate the construction of HVDC overhead lines, as these are more cost-effective than AC for such long-distance transmission (SNC-Lavalin and Brinckerhoff, 2011; Trieb *et al.*, 2015).

Third, we estimate the cost of the electricity supplied to the demand center by calculating and adding the generation and the transmission costs. We calculate the LCOE from a dry-cooled solar tower station with 10 hours of thermal storage at each site. This configuration will not produce baseload power, especially not during winter, but it will produce dispatchable, fully predictable and controllable renewable electricity (Mehos *et al.*, 2016; Pfenninger *et al.*, 2014a). We assume dry cooling for all stations, as wet cooling is rarely a viable option in deserts, and as the costs of dry cooling are relatively low (Damerau *et al.*, 2011). We choose solar tower over parabolic trough technology, as it achieves higher temperatures and hence a higher thermodynamic efficiency. Further, the flat mirrors and single receiver is more low-tech than troughs, enabling (at least in principle) the manufacturing of more components locally, thus potentially contributing to the local industrial and economic development (IRENA, 2013a). The power station costs are for a 100 MW, 10 hours-storage, molten-salt solar tower station similar to the United States Crescent Dunes station, with total costs of $7,910 per kW Turchi and Heath (2013). Following continued learning and cost reduction, we assume a 10% learning rate and the global CSP expansion scenario of the IEA's technology roadmap (IEA, 2014b). This implies that the CSP investment costs in 2025 are about 30% lower than in 2012. Detailed descriptions of the equations, the data and all sources are found in section B4 in Appendix B.

We then calculate the levelized transmission cost for a power line in the friction cost-minimized corridor, and add it to the generation cost. The transmission cost data is taken from the regional power system master plan for the Eastern African Power Pool and the East African Community. The cost for a 600 kV-HVDC bi-pole line is $150 per MW per km, for the converters stations (of which two, on at each line end, are needed) is $130,000 per MW, and for a 500 kV-AC double-circuit line is $290 per

MW per km (SNC-Lavalin and Brinckerhoff, 2011). Cost for transmission components remain as 2012 costs, as these costs are for projects planned by the regional power system master plan to start operation in 2025, same base year as our base case and scenarios (see sections 1.3 Base case and Scenario variations). The transmission line capacity factor follows that of the CSP station(s) connected to it, following the solar multiple-capacity factor equation of Trieb et al (2012) (see Eq. 11 in Appendix B).

To account for the financing risk of each generation-transmission project, we follow the *Investment Analysis* methodological tool developed by the Clean Development Mechanism's (CDM) Executive Board, which recommends using a country-specific WACC as financing cost when the project-specific financing cost is missing (UNFCCC, 2015b). We calculate country-specific WACCs as the weighted combination of equity and debt costs of each country (see Table 1). For the real equity rate of return K_{E_n} we use default values recommended by the CDM Executive Board for investment analyses in the energy industry for Non-Annex 1 countries (UNFCCC, 2015b). For the nominal prime-lending rate K_{D_n} we use the average lending rates for the period 2010-2014 (World Bank, 2015b). If this data is not available for a country for a specific year, we apply data from the last available year. For countries where K_{D_n} values are missing we replace missing values with data from neighbor countries as suggested by Ondraczek *et al.* (2015). We thus calculate the $WACC_n$ for country *n* as:

$$\boldsymbol{WACC_n = \frac{E}{E+D} \times K_{En} + \frac{D}{E+D} \times K_{Dn}} \quad (1)$$

where *E* and *D* are the equity and debt shares of the project; throughout, we use a 30:70 equity:debt share, which is common in renewable electricity projects risks (UNDP, 2013). For generation, we use the WACC of the country where the CSP station stands, whereas we apply the highest WACC along the corridor for the entire transmission project.

Table 1 Country-specific $WACC_n$ for the relevant SSA countries.

Country, demand center	K_{En} (%)	K_{Dn} (%)	$WACC_n$ (%) 30_{En}:70_{Dn}
Angola, Luanda	12.3	18.0	16.3
Benin, Porto Nuovo	14.6	16.8	16.1
Botswana, Gaborone	9.1	10.5	10.1
Burkina Faso, Ouagadougou	17.6	16.8	17.0
Cameroon, Douala	16.1	15.0	15.3
Ethiopia, Addis Ababa	14.6	8.0	10.0
Gabon, Libreville	13.2	15.0	14.5
Ghana, Accra	16.1	25.6	22.7
Mali, Bamako	16.1	16.8	16.6
Mozambique, Maputo	14.6	16.5	15.9
Namibia, Windhoek	11.1	8.8	9.5
Niger, Niamey	16.1	16.8	16.6
Nigeria, Lagos	13.2	16.7	15.7
Republic of the Congo, Brazzaville	13.2	15.0	14.5
Senegal, Dakar	14.6	16.8	16.1
Republic of South Africa, Johannesburg	10.7	9.0	9.5
Tanzania, Dar es Salaam	17.6	15.4	16.1
Uganda, Kampala	14.6	22.6	20.2
Kenya, Nairobi	14.6	16.6	16.0
Zambia, Lusaka	14.6	14.6	14.6
Transit or exporter country	**K_{En} (%)**	**K_{Dn} (%)**	**WACC 30 $_{En}$:70 $_{Dn}$**
Chad	16.1	15.2	15.5
Democratic Republic of Congo	17.6	33.4	28.6
Malawi	17.6	34.2	29.2
Sudan	14.6	17.0	16.3

Base case

In our base case, we calculate the cost of supplying CSP from the sites at the highest direct normal irradiance level available within each power pool[5] to the twenty demand centers representing the feed-in point of electricity supplied by CSP in each country, while considering current country-specific risks and constraining trade to within the existing power pools. We apply projected costs for 2025, as it is unlikely–given that no project is even in planning today–that large CSP or CSP with transmission projects will materialize anywhere outside the southern-most countries before then. Results with 2012 costs are found in Table F in Appendix B.

Investment costs on renewable infrastructure are usually higher in countries without active policy programs to support renewables, without local manufacturing capacity, and/or a lack of adequate logistic infrastructure, such as well-developed highway or railway systems (IRENA, 2015a). The CSP

[5] Tanzania is member of both the Eastern and the Southern power pool; we assign it to the Southern Power Pool, so as to be coherent with IRENA's SSA power system reports.

station investment costs apply for a new station constructed in the United States (see section 3.1 Model structure), where none of the above-mentioned difficulties exist. Thus, we assume a cost mark-up factor of 6% for stations constructed in Southern Africa, and of 26% for stations constructed in the remaining SSA, reflecting the cost-difference between SSA countries and more developed regions as described in IRENA (2015a). For the financing costs, we take country-specific risks into account by using country-specific WACCs, see Table 1.

We assume that no generators or transmission lines can be built in states currently classified as fragile (see section 1.2 Electricity cooperation in sub-Saharan Africa), as the investment risks and barriers are too large. Further, we assume that CSP projects with transmission can only take place within existing power pools, as the development of projects crossing power pool border would require the negotiation of new modalities for international electricity trade, but the political and administrative capacity for this may be limited.

Scenario variations

In a second step, we analyze the implications on costs and the location of transmission lines for five alternative scenarios, in which we relax the constraints on cooperation, reduce the financing costs compared to the base case, and remove the cost mark-up factor on the cost of components for stations constructed in SSA. As in the base case, we use projected CSP investment costs for 2025.

In the first scenario (2a), we relax the trade limitation and allow trade of electricity supplied by CSP between all countries, including currently fragile states. This variation represents an improvement in political stability and international cooperation capacity among SSA countries, resulting from successful policies to increase institutional capacities. This could enable some countries to access generation sites with higher direct normal irradiance and, with other conditions remaining the same, lower generation costs.

The second scenario (2b) considers an improvement in project finance, so that financing cost decrease from the country-specific WACC, which in SSA is often 15% or higher, to a uniform 5%, which can currently apply in particularly low-risk OECD countries (Schinko and Komendantova, 2016). This variation represents de-risking policies to reduce the perceived or actual investment risks and barriers, for example programs for concessional finance or loan guarantees.

In the third scenario (2c), we remove the cost mark-up factor for CSP components in SSA, assuming the same investment costs for SSA as for industrialized regions. This variation represents successful policies for technology transfer, improving the logistic infrastructure, and expanding local technical resources and expertise.

The fourth scenario (2d) considers a relaxation of all three assumptions simultaneously. This variation represents the most optimistic outlook for CSP, when all policy efforts for providing cheap finance, technology transfer, infrastructure improvements and measures to enable and enhance regional cooperation have been successful.

In the fifth scenario (2e), we limit electricity from CSP to be generated, transmitted and consumed domestically. This variation represents a situation where low institutional capacity hinders countries to cooperate at all, restricting CSP generation to the solar sites available domestically.

1.4. Results and Discussion

Base case

Our results show that under current economic and political conditions, electricity from CSP is competitive with coal power in the Southern power pool, except in Tanzania, when using 2025 technology costs. It is uncompetitive in all other parts of SSA, and in all countries if 2012 costs are used (see Table F and Figure C in Annex B). Figure 1 shows the costs in the demand centers, and the location of the CSP stations and associated transmission lines using 2025 costs. The cost figures described below represent 2025 costs.

In Southern Africa, the CSP supply from 2,900 kWh/m^2/year solar resources costs from 6.7 cents per kWh for Namibia, with excellent solar resources close to the capital Windhoek, to 9.8 cents per kWh for Tanzania, which also gets its electricity from CSP from Namibia through more than 3,000 km long transmission lines. This emphasizes that the transmission cost is not a main cost driver, but adds roughly 1–2 cents per kWh per 1,000 km line, depending on the country-specific WACC for the levelized cost of transmission. Tanzania, however, belongs not only to the Southern but also to the Eastern power pool. If Tanzania were considered to get power from the Eastern power pool, the cost of the electricity from CSP from Kenya, a neighbor country, would be more expensive (20.2 cents per kWh at 2,600 kWh/m^2/year, WACC 16%) than allocating Tanzania to the Southern power pool and hence getting the electricity from Namibia (9.8 cents per kWh at 2,900 kWh/m^2/year, WACC 9.5%), despite the length of the transmission line. In all Southern power pool cases, except Tanzania, the solar resource is domestic or in a neighbor country, and CSP supply to all countries could be competitive with coal power. Especially Namibia, South Africa, and Botswana are countries that are politically stable and have more efficient institutions than other Southern African countries. These countries are also among the countries with the highest average income and the lowest perceived level of corruption in all of Africa (Kaufmann and Kraay, 2016; Transparency international, 2016; World Bank, 2016b): it is no coincidence that South Africa is the one SSA country already expanding CSP. The generation areas we identify in Southern Africa are identical or similar to existing, under construction and planned CSP installations; for example KaXu (existing, 100 MW) or Xina Solar One (under construction, 100 MW) in South Africa, or Khorixas (planned, 22 MW) in Namibia (CSP Today, 2016).

In Western Africa, the CSP supply from 2,900 kWh/m^2/year solar resources from Niger costs about 14 cents per kWh, and–as in the Eastern and Central power pools–it is not competitive with coal power. The solar resources in Western Africa are comparable to those in Southern Africa, but the financing costs are much higher due to higher country risk levels: whereas the WACC in Namibia, South Africa, and Botswana is about 10%, the WACCs in Western African countries range from 15.7% for Nigeria up to 22.7% for Ghana (see Table 1).

In Eastern Africa, the CSP supply costs are about 13 cents per kWh. The maximum solar resources in Eastern Africa are 2,600 kWh/m^2/year, comparable to those in the southwestern of the United States where CSP stations are in operation. As the financing costs are too high, CSP is not competitive with coal power anywhere in Eastern Africa.

In Central Africa, the CSP supply costs are about 15 cents per kWh, although the best available solar resource is only 2,300 kWh/m^2/year, but the WACC of Cameroon is lower than in Eastern and Western African source countries. This resource level is the lowest of the four sub-Saharan power pools, yet it is higher than the solar resource in southern Spain, where CSP stations are in operation.

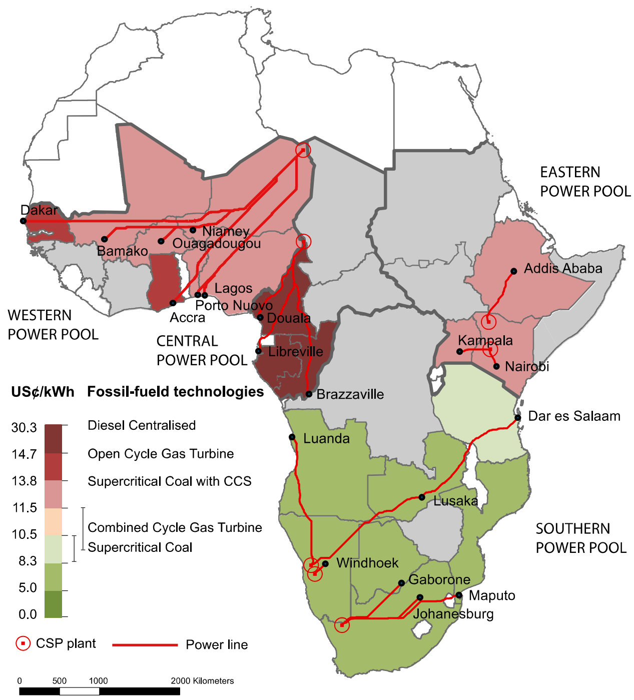

Figure 1 Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines under base case assumptions; using projected 2025 technology costs. Countries in grey are fragile states. The colors show the supply costs and compare them to typical costs of fossil fuel power plants in Africa (IRENA, 2013c, d).

Scenario variations

Scenario a: Unrestricted trade

Figure 2a shows the costs (2025) in the demand centers when electricity trade between all countries is allowed. In Eastern and Western Africa, the cost reductions of allowing electricity trade between all countries compared to the trade-constrained base case are up to 0.7 cents per kWh, whereas in Central Africa they are up to 5.7 cents per kWh (see Table 2). This makes the electricity from CSP roughly competitive with coal power in some countries in Central Africa, mainly because of the lower WACC in Namibia compared to the base case source country Cameroon. In Southern Africa there is no change, as these countries already access excellent, relatively low-risk resources in the base case. When electricity trade is allowed between all countries, Western and Eastern African countries receive its electricity from CSP from the very good solar sites in Niger, Chad and Sudan, whereas the Central African countries generate their electricity from CSP in Chad and Namibia. In some cases, the power station is built domestically (e.g. Namibia and South Africa) or in a neighbor country (e.g. Botswana), but for some demand centers up to 5 countries must be involved to access the highest resources. When electricity trade between all countries is allowed, all countries except Southern and some Western African countries involve more countries than compared to the base case, but get lower costs in return.

Table 2 Transmission distances (km) from cities to plants at the highest solar resources in Africa when electricity trade between all countries is allowed, number of countries borders crossed and associated cost saving (cents per kWh) for the year 2025 compared to plants at the highest solar resources within each power pool (base case). *np* means not possible.

	Distance (km)	Borders crossed	Cost saving (cents per kWh)
Western Power Pool			
Accra, Ghana	2,658	5	-0.6
Bamako, Mali	2,840	2	0.0
Dakar, Senegal	3,731	3	0.0
Lagos, Nigeria	2,304	2	-0.7
Niamey, Niger	1,743	0	0.0
Ouagadougou, Burkina Faso	2,175	1	0.0
Porto Nuovo, Benin	2,333	3	-0.7
Southern Power Pool			
Dar es Salaam, Tanzania	3,243	5	0.0
Gaborone, Botswana	869	1	0.0
Johannesburg, Republic of South Africa	1,014	0	0.0
Luanda, Angola	1,626	1	0.0
Lusaka, Zambia	1,628	3	0.0
Maputo, Mozambique	1,498	2	0.0
Windhoek, Namibia	151	0	0.0
Central Power Pool			

Brazzaville, Republic of the Congo	2,149	3	-5.1
Douala, Cameroon	2,236	2	-2.2
Libreville, Gabon	2,837	4	-5.7
Eastern Power Pool			
Addis Ababa, Ethiopia	1,886	1	-0.3
Kampala, Uganda	2,490	3	-0.1
Nairobi, Kenya	2,852	4	0.3

Scenario b: Improved financing conditions

Figure 2b shows the costs (2025) in the demand centers using a uniform 5% WACC for all countries. The impact of decreasing the financing risk is strong in Western, Central, and Eastern African countries where the financing risks are currently high: there, a uniform WACC of 5% halves CSP costs compared to the base case. For Southern African countries this effect is smaller, as the WACCs there are lower, but the cost reduction is still 2–3 cents per kWh (see Table H in Appendix B). The costs in Southern Africa are lowest, as the cost mark-up is lower than in the other countries, as the solar resource is higher, and the power lines are often shorter than in Western Africa with same solar resource. Under the assumption of uniformly improved financing conditions, electricity from CSP is competitive with coal power in all countries, with total LCOEs in all cases below 7.3 cents per kWh, indicating that policies to reduce financing costs are key to making electricity from CSP an attractive option in SSA.

Scenario c: No investment cost mark-up

Figure 2c shows the costs (2025) when the costs of the CSP stations are the same as for industrialized countries, without the cost mark-up. For Western, Central, and Eastern African countries, this reduces costs (compared to the base case) by about 3 cents per kWh, whereas it is some 0.4 cents per kWh in Southern Africa where the mark-up factor is lower (see Table H in Appendix B). In this scenario, the competitive/non-competitive status of the power supplied by CSP is the same as in the base case. This scenario thus indicates that issues such as a lack of skilled labor or weak infrastructure are important aspects, but they are not game-changers for the competitiveness of CSP, especially not in Southern Africa.

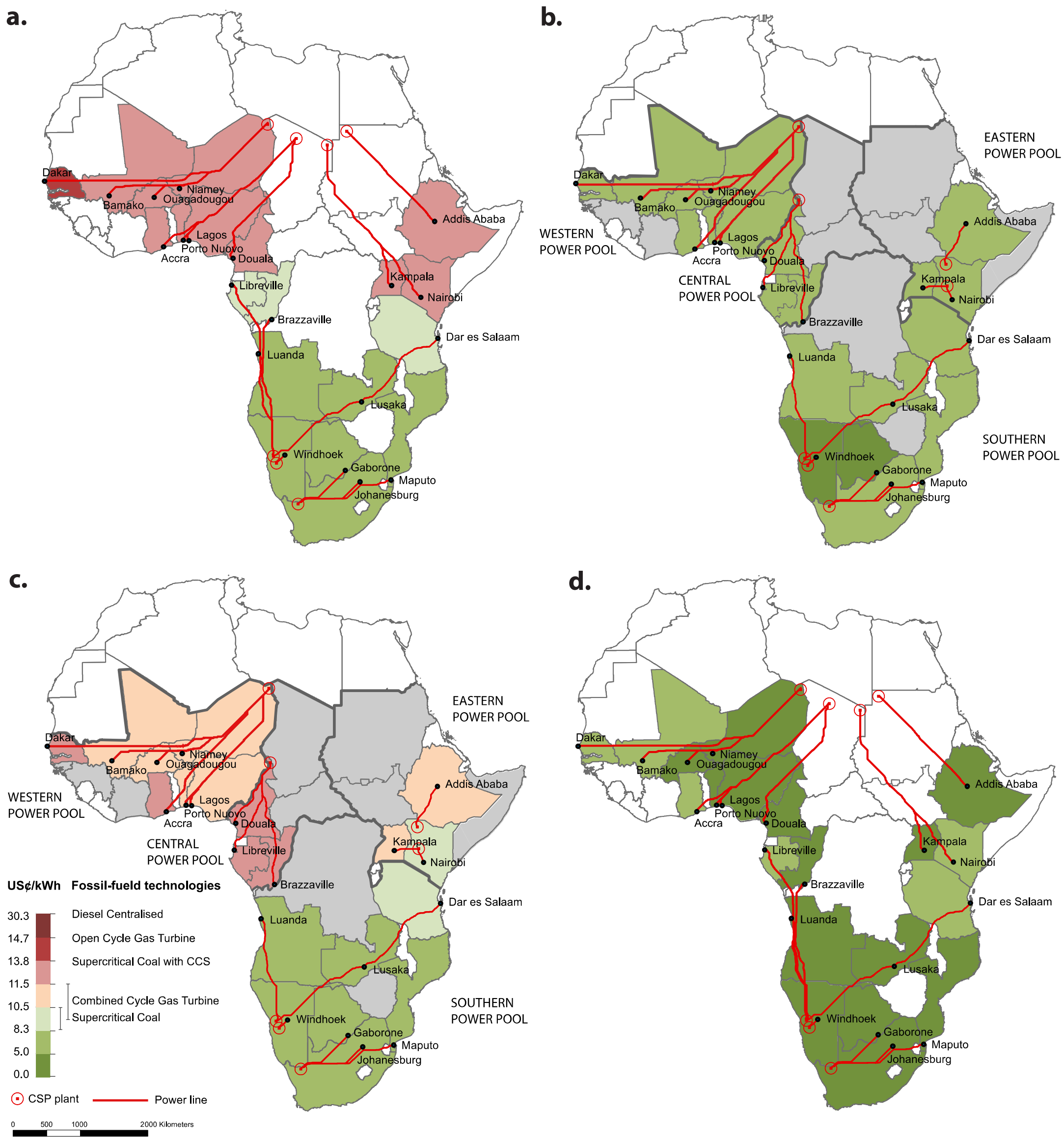

Figure 2 Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines using 2025 technology costs; (a) under unrestricted trade; (b) WACC 5%; (c) investment cost from industrialized countries; (d) considers all assumptions from previous scenarios. In (b) and (c) electricity trade is limited within each of the sub-Saharan power pools. Countries in grey are fragile states. The colors show the supply costs and compare them to typical costs of fossil fuel power plants in Africa (IRENA, 2013c, d).

Scenario d: Unrestricted trade, improved financing conditions and no investment cost mark-up

Figure 2d shows the costs (2025) in the demand centers after simultaneously relaxing all three non-technical assumptions of the three preceding cases. This makes electricity from CSP competitive with coal power in all countries, with costs around and below 5 cents per kWh (see Table H in Appendix B). In this very optimistic scenario, electricity from CSP is most likely the cheapest dispatchable electricity option of all, showing that policies to remove current barriers to CSP expansion have the potential to put SSA on track to a sustainable, reliable and highly affordable electricity supply.

Scenario e: Domestic solar resources

Similarly, countries may face a decision between exploiting the best possible solar sites, which are in some faraway place and are thus cheap but complicated to access, and the best solar sites available within the country, which may be more expensive in generation but easier to access. Countries such as Niger, South Africa, Namibia, Cameroon and Kenya have no reason to import power supplied by CSP as they have good solar resources available domestically. Imports are beneficial from a cost perspective in all other cases. Table 3 shows that for twelve countries is more economical to import power from other countries of the power pool than use domestic solar resources, and for other two is not even possible to use domestic resources as these are below 2,000 kWh/m^2/year, and they necessarily should import power. Accra (Ghana) could even save 9 cents per kWh, as it has both sub-par solar resources and high financing costs (WACC: 22.7%), but to access the best resources within the power pool (and hence lower costs), a transmission line of 2,500 km crossing 4 borders from Niger to Accra is needed. Hence, many countries have a choice to make, between cheap but complicated or simpler but more expensive power from CSP.

Table 3 Transmission distances (km) from cities to plants at the highest solar resources within each power pool (base case), number of countries borders crossed and associated cost saving (cents per kWh) for the year 2025 compared to plants at the highest domestic solar resources. *np* means not possible.

	Distance (km)	Borders crossed	Cost saving (cents per kWh)
Western Power Pool			
Accra, Ghana	2,495	4	9.0
Bamako, Mali	2,840	2	0.6
Dakar, Senegal	3,731	3	0.5
Lagos, Nigeria	2,251	1	1.6
Niamey, Niger	1,743	0	0.0
Ouagadougou, Burkina Faso	2,175	1	2.0
Porto Nuovo, Benin	2,281	2	2.8
Southern Power Pool			
Dar es Salaam, Tanzania	3,243	5	1.5
Gaborone, Botswana	869	1	0.4
Johannesburg, Republic of South Africa	1,014	0	0.0
Luanda, Angola	1,626	1	3.8
Lusaka, Zambia	1,628	3	3.2
Maputo, Mozambique	1,498	2	5.0
Windhoek, Namibia	151	0	0.0
Central Power Pool			
Brazzaville, Republic of the Congo	2,022	1	np
Douala, Cameroon	1,131	0	0.0
Libreville, Gabon	1,551	2	np
Eastern Power Pool			
Addis Ababa, Ethiopia	742	1	-4.0
Kampala, Uganda	362	1	4.7
Nairobi, Kenya	220	0	0.0

In the scenario variations a-d, the costs are lower than in the base case Figure 1, making electricity from CSP competitive with coal power in a larger number of countries. The largest single cost-reduction comes with improvements in project finance as shown in Figure 2b. Indeed, we confirm the finding for PV of Ondraczek *et al.* (2015), that the WACC is a stronger determinant of the cost of the power supplied by CSP in SSA than the solar resource quality. For example, consider the case of Cameroon: in the base case (Figure 1) the power is domestic (WACC: 15%, direct normal irradiance: 2,300 kWh/m^2/year) and costs 14.9 cents per kWh, whereas it is only 7.1 cents per kWh in case 2b (same as base case, but 5% WACC). However, in case 2a, with unrestricted trade, the power comes from the high-irradiance Chad (WACC: 15%, direct normal irradiance: 2,900 kWh/m^2/year) at 12.7 cents per kWh. Hence, improving the solar resource in this case to the best possible reduces costs by 2.2 cents per kWh, whereas lowering the WACC can reduce costs by up to 7.8 cents per kWh. Hence, Cameroon can import electricity from CSP from high-risk, high-irradiance Chad at high cost, or take policies (also in cooperation with the international community) to improve the financing conditions for its domestic solar resources and access much cheaper electricity (see Tables H-I in Appendix B for precise values for scenarios a-e).

1.5. Conclusions

We have shown that electricity from CSP is generally not competitive with coal power in SSA, even considering expected cost reductions up to 2025–except in Southern Africa, where solar resources are excellent and financing costs comparatively low. From a cost perspective, policy-makers may already view CSP as a viable supply option in these countries, even if the best resources are in another country. Here, the main challenge is not cost, but the institutional capacity for electricity cooperation. For the other countries in SSA, electricity from CSP is not competitive and cost reductions induced by technological learning alone will not change that.

Development along the three policy axes to improve institutional capacity and enhance multinational cooperation, de-risk finance, and improve technology transfer and domestic logistic infrastructure can however improve the cost outlook for CSP in SSA to the point of being competitive with coal power.

In most cases, importing electricity from CSP is cheaper than generating it domestically. Improving the capacity for international cooperation beyond the power pools could improve costs slightly, but at the cost of highly complex trading schemes between many countries and across existing administrative borders (e.g. outside existing free-trade areas, which also define the power pools). Similarly, removing the cost mark-up for CSP projects in SSA through policies for technology transfer and domestic infrastructure improvements would improve costs, but it would not on its own make power from CSP competitive with coal power.

The largest cost savings come not from accessing better solar resources–these are distributed across the continent, with every power pool having good and very good resources–but from accessing very good solar resources in lower risk countries. This will also increase the overall feasibility of CSP expansion: the same risks that increase costs may also make a project fully unfeasible, so that deviating to lower risk countries both reduces cost and improves the likelihood of a project being realized at all. Or, conversely, non-technical barriers such as political instability, weak institutions or corruption of many countries are particularly serious barriers for a CSP expansion in SSA.

The most important aspect to tackle for making CSP competitive across SSA is finance: policies to de-risk CSP finance to OECD levels could make power from CSP competitive with coal power in every country in SSA. Hence, the one measure that would support CSP the most is one of providing low-risk finance: through dedicated de-risking policies, such as long-term power purchase agreements, concessional loans, and/or loan guarantees, CSP could become competitive in all SSA countries, also without technology transfer or cooperation across power pools. In many cases, however, this also hinges on the capacity to cooperate among several countries, because not all countries have good domestic solar sites, and that political-administrative capacity is often lacking today. The issues of financing renewables and improving institutional capacity in developing countries are key issues in the Paris Agreement, and concrete policies to these ends are likely to be implemented as UNFCCC process continues in the next few years (UNFCCC, 2015a). Success on these issues could be immediately beneficial also for the industrialized countries: reducing the WACC of SSA CSP investments to OECD levels, and scaling CSP supply to the level of power consumption anticipated for SSA (IRENA, 2015a), over $10 billion could be saved annually, equivalent to about one fourth the current official development aid for SSA (OECD, 2016b).

We also showed, somewhat counter-intuitively, that financing risk is a more important determinant for the cost of CSP supply in SSA than the solar resource quality. This confirms previous findings for PV: also for PV, country risk is a stronger cost determinant than the solar resource quality (Ondraczek *et al.*, 2015). Whereas it would intuitively be beneficial to utilize better solar resources even if they are further away (as the transmission costs are much lower than the generation costs), we have shown that is generally cheaper to utilize lower solar resources in a low-risk country than to exploit better solar resources in a high-risk country.

Whereas we have shown that CSP with thermal storage can, if accompanying policies are implemented, be an affordable option for dispatchable renewable power, it is not the only possible option. In particular, solar PV coupled with batteries may also become an option to provide electricity of a similar quality. Current projections suggest that this will remain more expensive for large-scale dispatchable renewable power than CSP with thermal storage, but given the enormous pace of both PV and battery development, there is reason to believe that this combination may make huge technological strides in the next few years, possibly overtaking CSP as the cheapest dispatchable renewable option: projections of PV and battery costs have repeatedly been far too pessimistic, and this could apply in this case too. Thus, we suggest further research on the technical, economic, and political requirements, including technology scenario analysis, for making solar PV with battery storage a viable solution for large-scale dispatchable supply in Africa and other developing regions.

In this article, we have shown that the future of CSP in SSA hinges critically on improvements of the political-administrative aspects leading to increased project feasibility and reduced financing costs: without that, electricity from CSP will be economically viable only in a few Southern African countries, but with successful policy efforts, CSP with thermal storage could become competitive across the continent.

CHAPTER 5. Broader implications for policy making

My overarching research objective in this thesis was to determine how specific challenges and barriers for solar power deployment can be removed, and what are the benefits of addressing these challenges for a country that decides to expand solar power, driven by climate, social or environmental objectives. The three research contributions determine the impact of removing air pollution to increase variable solar power generation and suggest that, under certain conditions, controllable concentrating solar power coupled with thermal storage and long-distance transmission might be an affordable solution to preserve power systems' reliability when increasing the share of variable renewables in the grid; this solution may become affordable for sub-Saharan African countries particularly when financial and political barriers are removed.

In the following, I present the three contributions' broader implications for policy making, while I also present their limitations, methodological insights, and outlook for further research.

The findings of *Contribution I* advance our understanding of the effect of air pollution on solar power generation and of policy instruments that might help justify systemic measures across fossil fuel sectors other than improving public health. Reducing air pollution can increase solar power generation from the current photovoltaics fleet without installing one single additional megawatt. Therefore, policy instruments to reduce emissions from fossil fuel sectors–namely, energy, industry, transport, and residential and commercial–may not only help mitigate climate change and improve public health and agricultural yield, but also drive an increase in solar power generation. This is the first time that an emissions' inventory per sector has been used to estimate the influence of individual sectors' emissions on solar power generation. However, this method has limitations: the emissions' inventory dates back to 2014, impeding the analysis of recent emissions data until the release of the new inventory.

The findings of *Contribution I* have broader implications for climate and public health policies, particularly in countries with similar problems breathing polluted air and with renewable energy targets on solar power. Further research might expand to countries experiencing acute levels of air pollution like India or African countries such as Egypt, Tunisia, South Africa, Nigeria, and Kenya, all of which are endowed with high solar resources. In Africa, the number of deaths caused by ambient air pollution has increased by over 36% in the last three decades and has caused about $215 billion of economic losses every year (OECD, 2016a). In principle, to make the case for enacting air pollution mitigation measures, it would suffice to show that the cost of these measures is lower than the benefits they would secure. There is evidence from developed countries that mitigation measures on air pollution cost a small fraction of the benefits they secure from avoiding premature deaths: in the United States, the Clean Air Act Amendments of 1990 delivered an estimated cost-benefit ratio of 1:31, while the

European Union's Clean Air Package delivered an approximate cost-benefit ratio of 1:42 (WHO, 2015). While many African countries struggle with air pollution, only a few governments have enforced formal regulations against emissions. Similar cost-benefit appraisals, like those for the United States and Europe, might prove useful for policymakers in India and African countries to enact air pollution mitigation measures.

In addition, in *Contribution I*, I introduce a methodology to determine the direct economic losses for solar investors because of air pollution, which provides a new way for accounting to affect the energy industry, with different actors and interests from those in public health. This methodology can also be used to examine the effects of air pollution on concentrating solar power, as air pollution reduces the level of direct normal irradiance necessary for the plant to operate (Kvalevag and Myhre, 2007). However, because concentrating solar power plants need a minimum level of direct normal irradiance to operate, these locations may be far from urban areas where pollution levels are usually the highest. In this case, a prescreening of solar resources' location and areas affected by air pollution might prove useful before performing the analysis.

The results of *Contribution II* advance our understanding of supplying perfectly controllable solar power to the power grid. Given that almost 20% of total solar and wind generation in China is curtailed because of a lack of transmission capacity or regulations granting priority to electricity from coal, a first understanding of the cost and transmission requirements to benefit from concentrating solar power to help accommodate variable power in the grid might prove useful for policymakers. The limitation of this study is that I examined the role of one technology in the power system, while other carbon-neutral technologies also can supply controllable power on demand. Given that the Chinese power sector is undergoing unprecedented changes from a supply and demand perspective, further research investigating the role of a range of controllable and carbon-neutral technologies in power regions might prove useful for policymakers, who may also benefit from insights derived from diverse energy capacity expansion scenarios. Therefore, further research might identify optimal locations for both controllable and variable renewable power generators under centralized and decentralized configurations of generators and optimal configurations of transmission corridors regarding capacity, route, and length. These scenarios would inform policymakers about the power system configurations that minimize system costs and make the grid more flexible and reliable while meeting constant electricity demand. A limitation of *Contribution II* is the use of short-term time series of meteorological data. Further research would greatly benefit power system modeling from long-term time series, that is, 25–30 years, of wind and solar photovoltaics power output because of considerable inter-year variability in weather data (Pfenninger, 2017). The use of these long-term time series might help address complex inter-grid electricity flows of an interconnected power system that fluctuating power feeds, varying all the seconds, minutes and years.

The findings of *Contribution III* advance our understanding of the influence of financing costs on the success of renewable energy projects. Notably, this is the first time that scientific studies have used country-specific financing costs to examine long-distance transmission. Because of a lack of project-specific financing cost data, I followed the Investment Analysis methodological tool that the Clean Development Mechanism's Executive Board developed (UNFCCC, 2015b) to calculate the financing costs for each generation-transmission project from country-specific equity rates of return and lending rates. Despite this practice being common, it is still a limitation of this study. Data on prime lending rates for business, that is, what banks charge when lending to costumers, shows that business in Africa pay on average a lending rate of 15%, which is about 5 percentage points more than what business pay in India and about 10 percentage points more than what business pay in China (CIA, 2018a). This phenomenon might be due to inefficiencies in the banking system, lack of competition, and higher risk associated with African businesses. Further research on ways to reduce financing costs on renewable energy projects might prove useful for policymakers aiming to increase the deployment of renewable energy in African countries. A World Bank (2018b) study identifies several risks associated with concentrating solar power projects in Africa and proposes mitigation strategies. The key risks identified are associated with a country's financial sector and technical design risk, which decreases as plant operators gain experience. The mitigation strategies are, for instance, the use of concessional climate finance and government subsidies. Therefore, the methodology I use in *Contribution III* and the World Bank's research might serve as a first step for further research to gain an understanding of specific country risks and decrease financing costs in African countries.

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Appendix A: Supporting Information for Contribution I

A1 Cost of adopting best-practice emission standards in fossil-fueled sectors

A1.1 Electricity generation for public use and plant consumption

Near-zero emissions power plants are equipped with a combination of multiple emission-removal technologies (World Coal Association, 2017), consisting of three stages: the removal of particle matter (PM) with a fabric filter or with a dry electrostatic precipitator (ESP) equipped with a low-temperature economizer, as well as during desulfurization through a high-efficiency wet flue gas desulfurization (WFGD) system. The ESP or fabric filter has a PM removal efficiency of 99.8–99.9%, which reduces the concentration of PM to below 20 mg/m^3. Emissions of SO_2 are controlled using a high-efficiency WFGD system with a removal efficiency of ~99%, which also removes and additional ~50% of PM entering the system. This synergetic PM removal reduces the concentration of PM to below 15–10 mg/m^3. In a final step, a wet ESP removes and additional ~70% of PM, which reduces the concentration of PM to below 5 mg/m^3. A full-load denitration system, together with low-NO_x combustion in the boiler, has a NO_x-removal efficiency of ~85%, which reduces NO_x emissions to 40–10 mg/m^3.

The Shenhua Guohua Power Company has been an early adopter of near-zero emissions technologies. Retrofitting coal-fired power plants to reach near-zero emissions increases electricity generation costs. The incremental generating costs of reaching near-zero emissions, after accounting for the investments for retrofitting and being discounted over 15 years, for the plants Zhoushan No.4, Dingzhou No.3, and Sanhe No.1 are 0.1, 0.1, and 0.16 cent per kWh, respectively (Shumin, 2015). When comparing the total generating costs of a near-zero emissions plant to those of a natural gas combined-cycle plant, the generating costs of a natural gas combined-cycle unit in the province of Zhejiang is 9.36 cent per kWh, while those for Zhoushan No.4 in the same province is 3.1 cent per kWh–about one-third as much (Shumin, 2015).

Retrofitting coal-fired power plants with the above-described combination of emission-removal technologies to reach near-zero emissions will increase electricity generation costs by 0.1–0.16 cent per kWh (Shumin, 2015). Because the thermal electricity generation (~90% coal-fired) in China in 2014 was 4,222 TWh (Fridley *et al.*, 2016), which accounts for the plants that generate electricity for sale to third parties and for the electricity used in plants for their own purposes, the cost of retrofitting the thermal plants is between \$4.2 and 6.7 billion/year.

We assume that the costs of retrofitting the combustion process for heat generation from electric boilers plants and the combustion processes in transformation processes with the same combination of air pollution control systems as is used for electricity generation are proportional to the level of SO_2 emissions and thus amount to \$1.5–2.3 billion/year and \$1.5–2.4 billion/year, respectively.

Hence, the total retrofitting cost in the energy sector, i.e., electricity and heat generation plants and transformation processes, amounts to \$7.2–11.4 billion/year.

A1.2 Industrial combustion and industrial processes

Industrial boilers provide heat or process steam to meet the needs of the facilities in which they are installed. These facilities can be parts of the iron and steel industry, the chemical and petrochemical industry, the non-ferrous metals and non-metallic minerals industry, etc. While emissions from coal-fired power plants and coal-fired industrial boilers are affected by a number of variables such as coal type and composition and the type of combustion technology, the emission control technologies used to limit emissions from stack gases are essentially the same (World Bank, 2018a). Hence, we assume that coal-fired industrial boilers are retrofitted with the same combination of air pollution control systems as is used in coal-fired power plants and that the cost is proportional to the level of SO_2 emissions and thus amount to \$12.0–19.1 billion/year.

It is also possible to replace the use of coal in industrial boilers with another, less-polluting fuel, such as natural gas. In many cases, converting coal-fired boilers to gas-fired boilers can be profitable because the changes to the equipment are likely to be less expensive than installing air pollution control equipment; also, the use of natural gas would lead to lower emission characteristics.

China’s natural gas production is rising at a fast pace but not fast enough to meet the demand required by the government to clean the country’s air. China has the world’s largest reserves of shale natural gas, and much of it could be recovered if cost were not a limitation (South China Morning Post, 2018). The boilers and stoves used in the residential and commercial sectors are difficult to retrofit with effective pollution control equipment because of the small scale and age of the units, and it is also difficult to ensure that these units operate correctly. Hence, we assume that the residential and commercial sectors will switch to natural gas, while the industrial boilers will be equipped with the same pollution control equipment as is used in coal-fired power plants.

We discuss the industrial processes in the main text in the section *Clean-air policies and their cost*.

A1.3 Road transport and domestic navigation

Gasoline and diesel fuels contain sulfur because it is a natural component of crude oil. The sulfur content in the fuel is the most important parameter affecting the introduction of measures to limit end-of-the-pipe emissions: a fuel with a sulfur content of ~50 ppm (parts per million) allows for the use of diesel particulate filters with an efficiency of ~50% and for the selective catalytic reduction (SCR) of NO_x with an efficiency of ~80%. In contrast, a fuel with near-zero sulfur content of ~10 ppm enables huge advances in fuel-efficient vehicle design and advanced control technology because it allows for the use of NO_x absorbers with an efficiency of over 90%, which enables engine designs with higher fuel efficiency and particulate filters that achieve an efficiency close to 100%, thereby emitting ~99% less $PM_{2.5}$ than uncontrolled vehicles (Blumberg *et al.*, 2003).

The costs of reducing sulfur content in the fuel depend on the state of existing refineries, current fuel quality, and emissions standards but such costs can be divided into two types: the cost associated with fuel production and the cost associated with vehicle emission control technologies. Estimates of the costs associated with fuel production accounts for upfront refinery investment, such as capital equipment upgrades, and direct operating costs, such as catalysts and chemicals (ICCT, 2015a). The costs of upgrading China's refineries to produce near-zero sulfur 10 ppm gasoline and diesel fuels are 0.7 cents and 1.7 cents per liter, respectively (ICCT, 2012), which is comparable to international experiences and equivalent to 0.6–1.5% of the pump price. This translates into a total investment requirement of $4.3 billion/year after accounting for upfront refinery investments, such as capital equipment upgrades, and direct operating costs, such as catalysts and chemicals (ICCT, 2015a).

Estimates of the cost for the introduction of advanced emission control technologies in vehicles account for the additional costs to manufacturers for equipping these vehicles with advanced emission control technologies to meet international best-practice standards, i.e., the adoption of the China 6 standard in gasoline and diesel vehicles. Table A shows the additional costs for manufacturers for equipping a vehicle with advanced emission control technologies to meet the China 6 standard, which for the current vehicle fleet amounts to $7.4 billion/year (ICCT, 2015a).

Table A Additional cost ($) per vehicle for manufacturers when they are compelled to install an emission control technology to meet the China 6 standard, over an uncontrolled emission level. Numbers adjusted based on engine size and labor and other expenses that are specific to China (ICCT, 2015a).

Fuel	Large Buses	Private Cars	Light Trucks	Heavy Trucks
	Diesel	**Gasoline**	**Diesel**	**Diesel**
China 6	4,765	366	4,248	9,200

Note: Costs reflect the incremental cost to manufacturers, not the price increment paid by the consumer. The additional costs are multiplied by the number of projected vehicles sold for each vehicle type by fuel type. The vehicle fleet does not account for motorcycles.

The adoption of international best-practice standards such as ultra-low sulfur standards and the China 6 standard, will lead to a total additional cost of $11.7 billion/year. These costs assume that all vehicles that emit a disproportionate share of total emissions, known as "yellow-label vehicles," will be scrapped. Although scrappage is a near-term measure to reduce air pollution, China is implementing one of the most ambitious voluntary scrappage programs for old vehicles worldwide because it will result in rapid urban air quality improvements.

China has introduced standards regarding the content of sulfur in the fuels used for navigation, to limit the content of sulfur to 3.5% m/m (mass of sulfur/total mass, or 35,000 ppm). As of 1 January 2018, vessels that operate in the Yangtze River Delta, the Pearl River Delta, and the Bohai Sea should use fuels with a sulfur content of less than 0.5% m/m. The International Maritime Organization (IMO) will extend this limit to all international ports two years later (IMO, 2016). Ships navigating in sulfur emission control areas, i.e., the North Sea, the Baltic Sea, the English Channel, and the North American coasts, should use fuels with a sulfur content of less than 0.1% m/m. China is also considering reducing the allowable sulfur content to 0.1% m/m, which will reduce SO_x emissions by ~97%.

There is not a single way forward to reduce or eliminate sulfur and related emissions from navigation. The options include continuing to use heavy fuel oil (HFO) while also cleaning the exhaust gas with scrubbers; switching to a low-sulfur fuel, such as marine gas oil (MGO) or liquefied natural gas (LNG); or a combination of both. Thus, ship-owners will have to choose whether to invest in scrubbers or use low-sulfur fuel, a choice they will make based on the ship's age, the price of scrubbers and their operational costs, and the price differential between high-sulfur and ultra-low-sulfur fuels.

Switching from HSFO to MGO or MDO with a sulfur content of 0.1% m/m is a straightforward solution for carriers because engines do not need to be retrofitted with emission control technologies to accept this type of fuel, although minor adjustments in auxiliary equipment are needed in some cases. The costs of equipping an average-size medium-range ship of 10MW to adapt to MDO or MGO, i.e., installing a fuel cooler or chiller and the associated piping prior to the fuel pump to decrease fuel viscosity, and also SCR technology, are about $0.8 million and $0.5 million, respectively; and the operational cost derived from the use of the reducing agent in SCR is about $0.2 million per year (EIA, 2015c; NRDC, 2014). The capital costs of SCR systems, which vary with engine design, are the stronger determinant of the system's costs. In general, the larger the engine, the less expensive the installation costs are per MW.

China has about 2,400 Chinese-owned oceangoing container vessels in its waterways (Chinese Ministry of Transport, 2016), a number in line with the 2,444 vessels provided by the World Factbook, which are comprised of 1,069 bulk carriers, 198 container ships, 697 general cargos, and 480 oil tankers (CIA, 2018b). If 2,400 container vessels switch from HSFO to MGO at a cost of $1.5 million per ship, the total cost of the container fleet switching fuels will be $3.6 billion/year.

China has also about 10,500 coastal vessels, including small passenger ships, fishing boats, etc., and 147,200 river vessels (Chinese Ministry of Transport, 2016). Most of the fishing boats and small passenger ships already operate with low-sulfur fuel oil due to their limited sizes and hence limited engine capacities.

Overall, low oil prices favor solutions with the lowest capex, i.e., MGO, while high oil prices favor solutions with a higher capex, i.e., scrubbers or liquefied natural gas (LNG). Under stricter international emission standards, the demand for scrubbers may increase, and the costs may go down as production scales. Also, the price of HSFO is expected to fall sharply when the cap set by the IMO comes into force in 2020, while the price of ULSFs is expected to dramatically increase. Thus, the use of scrubbers may be the most cost-effective way for larger ships to comply with the sulfur limit.

Emissions from the transport sector originate not only from road transport and navigation, but also from the combustion processes in rail transport. Emissions from rail transport account for 3% of SO_2 emissions from the transport sector, or 1% of total SO_2 emissions from all sectors. Thus, because emissions from rail transport are not significant, we exclude rail transport when estimating the cost of reaching near-zero emissions. Hence, the total cost of reducing emissions in the transport sector due to road transport and domestic navigation is $15.3 billion/year.

A1.4 Residential and commercial sector

Households and businesses in China burned 119 million tons of coal in 2014, which accounted for 4% of total national consumption (Fridley *et al.*, 2016). Both the boilers employed to heat residential and commercial buildings and stoves used for cooking lack effective pollution control equipment and retrofitting them with such equipment is difficult because of the age and small scale of the units, as well as the difficulty of ensuring that these units operate correctly. Also, the cost of retrofitting the units may be too high for poor owners.

To significantly improve air quality at the urban level, the burning of coal and other pollution sources, such as wood, biomass, and waste, can be replaced with natural gas or propane. Also, it is possible to switch to electrical appliances fed with electricity from low-emission sources, though the prior method is the most efficient way because the equipment is already in place. To reduce air pollution levels, cities and villages in Northern China and, more notoriously, the nation's capital, Beijing, have started to replace coal-fired residential heating and cooking with gas-powered stoves and boilers.

Table B shows that to replace coal in residential and commercial uses with natural gas or propane, China would need to procure an additional 93.86 billion m^3 of natural gas, which would represent a 70% increase over the total of 159.32 billion m^3 of natural gas consumed in 2014 (Fridley *et al.*, 2016). In our calculations, we assume that the switch is made to a single fuel, i.e., natural gas, because in East Asia the costs per unit of energy of natural gas and propane are similar. We also assume that one energy unit of natural gas can substitute for one energy unit of coal in household and commercial users; which is a conservative assumption because the new natural gas heating devices are likely to be more efficient than old coal-fired boilers.

Table B Replacing coal with natural gas for residential and commercial use in China.

	Coal Use (Mtce)	Conversion	Natural gas equivalent (billion m^3)
Residential rural	78.11	0.786	61.39
Residential urban	14.42	0.786	11.33
Commercial	26.90	0.786	21.14
Total	**119.43**		**93.86**

During the first half of 2017, average natural gas pipeline import prices in China averaged \$187 per m^3, while LNG import prices averaged \$253 m^3 (EIA, 2018b). At a price of \$187 per m^3, the cost of an additional 93.86 billion m^3 of natural gas is \$17.55 billion, and at a price of \$253 per m^3, the cost is \$23.74 billion.

Table C shows the annual net cost of replacing coal with natural gas for residential and commercial use. The average prices of imported anthracite and imported bituminous coal are

$58.90 per ton and $68.76 per ton, respectively (Fridley *et al.*, 2016). Subtracting the average value of the coal for which these fuels would substitute, at an average coal price of $63.83 per ton, this results in $7.62 billion. Hence, the net annual costs are from $9.9 billion to $16.1 billion/year. We acknowledge the volatility of the price of natural gas, which can influence the results. The import prices for natural gas via pipeline and LNG during 2015-2016 were rather stable, but in previous years, the prices had been more than 50% higher.

Table C Annual cost of replacing coal with natural gas for residential and commercial use.

Policy measure	Quantity natural gas (billion m^3)	Price natural gas ($ per m^3)	Total annual cost (billion $)	Net annual cost (billion $)
Price pipeline import	93.86	187	17.55	9.93
Price LNG import	93.86	253	23.74	16.12

We do not estimate the investment cost of converting a coal-fired boiler to a natural gas-fired boiler, because of the lack of available data on the capacity of installed residential and commercial boilers and the cost of replacing those boilers. It is likely that the costs of converting boilers will represent a small share of the total costs and savings from shifting from coal to natural gas or propane. Also, switching from coal to gas involves the construction of natural gas distribution networks, pipelines, and household connection facilities, the prices of which are uncertain. Hence, we acknowledge these uncertainties and exclude these estimates from this analysis.

A2 Evaluation of the global aerosol-climate model ECHAM6.3-HAM2.3

A comprehensive evaluation of the individual factors contributing to the modelled surface solar irradiance in ECHAM6.3-HAM2.3 including cloud cover and aerosol indirect effects is in preparation and will be published elsewhere. Here, we answer the question of how realistic modelled surface solar irradiance under all-sky conditions, i.e., including clouds, is in China. We also examine the plausibility of modelled surface solar irradiance changes under changing anthropogenic aerosol emissions.

Regarding the first question, we show that ECHAM6.3-HAM2.3 captures well the overall magnitude and spatial pattern of all-sky surface solar irradiance in China. Figure A compares the annual mean surface solar irradiance from ECHAM6.3-HAM2.3 (remapped onto the CERES grid and CEDS aerosol emission data for the year 2014 (Hoesly *et al.*, 2017)) and CERES (from 2005 to 2015 (Loeb *et al.*, 2018)) for China and neighboring regions. Figure Aa-b show an overall similar range of surface solar irradiance for ECHAM6.3-HAM2.3 and CERES of ~100-250 W/m^2 and a similar geographical distribution: particularly low surface solar irradiance in parts of eastern and south-central China (notably around 30N and 105E, in the basin area of Chengdu and Chongqing), as well as particularly high surface solar irradiance in parts of western China and the Tibetan plateau with its high elevation. Figure Ac shows that the difference in surface solar irradiance between the two data sets is within ±10 W/m^2 in most parts of China, particularly in eastern China, where the majority of the population resides.

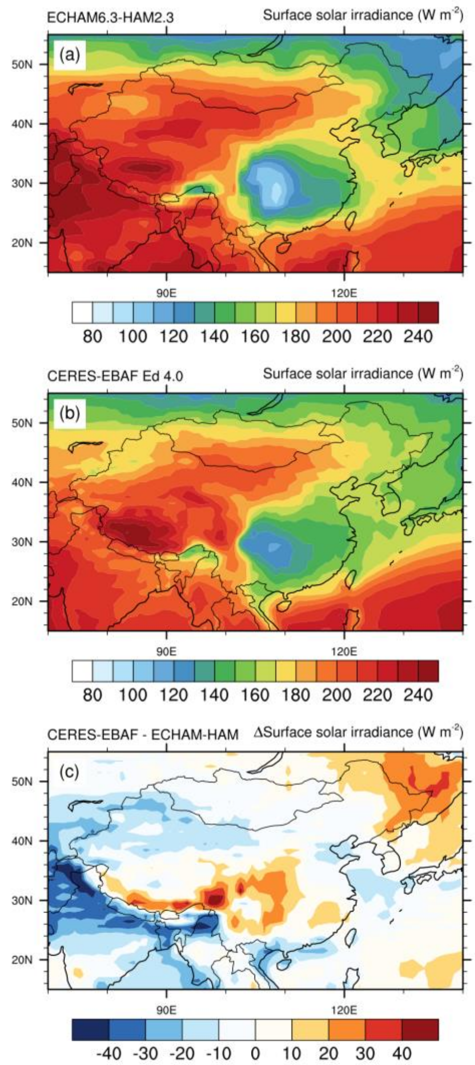

Figure A Annual mean surface solar irradiance (W/m^2). Annual mean surface solar irradiance from ECHAM6.3-HAM2.3 (a) (Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012), CERES-EBAF (b) (Loeb *et al.*, 2018), and the difference of CERES-EBAF and ECHAM6.3-HAM2.3 (c); created with (UCAR/NCAR/CISL/TDD, 2017).

The largest differences (dark red) are found around 30N and 100E, a region of very steep topography as the terrain ascends towards the Himalaya/Tibetan Plateau and where, consequently, neither the modeled nor the satellite data with their comparatively coarse spatial resolution can be considered very reliable.

Similar considerations apply to the reddish patches further to the west, in the flanks of the Himalaya, as well as to the dark blue patches in the north west, the Tian Shan mountains. In the remaining reddish and bluish areas, differences between ECHAM6.3-HAM2.3 and CERES are mostly smaller than ±20 W/m^2. Reasons for these differences comprise again topography, but also natural and anthropogenic aerosols as well as clouds and aerosol-cloud interactions and water vapor.

In the west, the overestimation of surface solar irradiance in ECHAM6.3-HAM2.3 with respect to CERES (bluish colors) is equally present for clear sky conditions, which indicates that aerosols or water vapor play a role for the difference. Yet water vapor as the only cause seems questionable given that the difference is between 10-20 W/m^2. A reason can be an underestimation of natural aerosol, notably mineral dust, in ECHAM6.3-HAM2.3. An underestimation of anthropogenic aerosol emission seems less likely, as such emissions are comparatively small in this region in the first place. The latter is in line with the fact that there is essentially no observed change in surface observations of sunshine duration since 1960 (Figure 5 in (Du *et al.*, 2017)). The difference between modeled and satellite data is dependent also on the contribution from clouds / cloud properties, and particularly in the central region of China clouds show a strong seasonality (monsoon).

In the reddish area from 100E to 110E and from 26N to 32N, where the surface solar irradiance from ECHAM6.3-HAM2.3 is 30-40 W/m^2 lower than in CERES, the situation is slightly more complicated as this is a hot spot region of anthropogenic aerosol emissions, as given in CEDS emissions data. Again, the difference seen in all sky surface solar irradiance is in line with the clear sky difference. This again indicates that aerosols play a role for the difference between modeled and satellite, but the influence of clouds cannot be excluded.

After comparing the results from ECHAM6.3-HAM2.3 and CERES satellite data, we note that studies comparing surface solar irradiance from CERES with surface solar irradiance from surface observations find a general overestimation of surface solar irradiance in China by CERES on the order of 10W/m^2, see (Ma *et al.*, 2015) Figure 4 and Table 6 and (Zhang *et al.*, 2016) Figure 3 and Table 5, which confirm the results of ECHAM6.3-HAM2.3 regarding the range and spatial pattern of all-sky surface solar irradiance in China.

Regarding the second question, we show that modeled surface solar irradiance changes are in line with observation-based estimates of surface solar irradiance reduction from anthropogenic aerosol emissions since the 1960s. We have shown that in eastern China, changes in modeled solar irradiance are up to ~25 W/m^2 and in the central region up to ~30 W/m^2 (Figure D and Table J). Published estimates of anthropogenic aerosol induced dimming in China show a total reduction from the 1960s till today of 20 W/m^2 or more (Figure 5 in (Shi *et al.*, 2008); Figure

3c in (Yang *et al.*, 2015); Figure 10 in (Folini and Wild, 2015); Figure 5 in (Du *et al.*, 2017)). These studies show that the observed reduction of surface solar irradiance is strongest in the eastern and central parts of China and it is similar to our results; yet these studies also show diverse results as to when and where in eastern China the observed reduction of surface solar irradiance is the strongest. A more detailed comparison of modeled surface solar irradiance in ECHAM6.3-HAM2.3 with observation-based estimates is beyond the scope of this study.

In summary, absolute all-sky surface solar irradiance is modeled reasonably well by ECHAM6.3-HAM2.3 and that modeled, anthropogenic aerosol induced surface solar irradiance changes are plausible as compared to published observation-based estimates of changes in solar irradiance.

A3 Policies to control and reduce air pollution

China has been implementing policies to control air pollution for more than three decades. However, it was not until the Ninth Five-Year Plan (FYP) (1996-2000) that the first target to limit total national SO_2 emissions was introduced. The target was few million tons higher than actual emissions, and it was achieved. The Tenth FYP (2000-2005) set a national target to reduce SO_2 emissions by 10% by 2005 as compared to 2000 levels. Policies to control emissions included equipping new and existing coal-fired power plants with desulfurization systems; the phase-out of small, inefficient power plants with poor technology and high pollution discharges; the replacement of these power plants with larger, more efficient units; a higher pollution levy rate; and stricter emission standards. At the end of the period, about 14% of the coal-fired capacity had desulfurization systems installed, yet less than half of these were running continuously and reliably (CEC, 2006; SEPA, 2007). These policies proved insufficient to meet the national target.

The Eleventh FYP (2006-2010) held the same national emissions target, but it was stricter in some provinces and implemented more ambitious policies (National People’s Congress, 2006). These policies included a doubling of the pollution levy rate, stricter regulations on the closure of small, less-efficient power plants, a price premium for electricity generated from plants with desulfurization systems, financial assistance for the installation of desulfurization systems, and fines to plants if such systems were in operation less than 90% of the time. As a result of these measures, SO_2 emissions from the electric power plants began to fall in 2006, with a reduction of about 36% from 2006 to 2010 (Figure 2 in main text). The percentage of coal-fired capacity with desulfurization systems increased to 86% in 2010 (CEC, 2011). This time, the policies proved sufficient to meet the national target.

The Twelfth FYP (2011-2015) established air pollution prevention and control measures not only in the power sector but also in high-emitting industries, including the iron and steel, cement, pulp and paper, non-ferrous metals, and flat glass industries, as well as on transport. The plan introduced, for the first time, politically binding targets for SO_2, NO_x, and CO_2 intensity (MEP, 2011). The emission standards became stricter and were comparable to those in Europe and the United States. The Emission Standard for Air Pollutants from Thermal Power Plants limited SO_2 emission concentrations for new and existing coal-fired plants to 100 mg/m^3 and 200 mg/m^3, respectively, except in some provinces where the coal used to fuel the plant has a high sulfur content. There, higher emission limits were allowed (MEP, 2011). For *key regions* of pollution control, which account for more than 66% of China's GDP, the limit was 50 mg/m^3.

In 2013, a winter-long episode of severe haze over many provinces and cites in eastern China became worldwide news. The concentration of $PM_{2.5}$ in Beijing, for instance, was 40 times the limit recommended by the World Health Organization (Wong, 2013). As a consequence, air pollution control policies were strengthened on multiple fronts. The China National Action Plan on Air Pollution Prevention and Control (2013–2017), the country's toughest move to reduce air pollution, set limits to coal consumption for the power and industrial sectors. For the industrial sector, the plan also included the promotion of technology upgrades, stricter controls on high-polluting and energy-intensive industries, and the shutdown of the most polluting factories (IAE, 2016). The plan also set stricter air quality standards for the most polluted eastern regions, i.e., the Beijing-Tianjin-Hebei, Yangtze River Delta, and Pearl River Delta regions.

In 2014, the Coal Energy-Saving Upgrade and Transformation Action Plan (2014–2020) went into force, requiring all new and existing plants to limit SO_2 emissions to 35 mg/m^3 by 2020 (MEP, 2015). Shenhua's Sanhe Power Plant 1, one of the plants on which we based the cost estimates, was China's first coal-fueled unit that successfully underwent a retrofit to comply with the emissions limit (World Coal Association, 2017).

A4 Counterfactual scenarios

The counterfactual scenarios represent the emissions of the energy sector if no pollution control policies had been introduced since 2006 and the emissions of the industrial sector if the same pollution control policies as used for the energy sector had been applied to industry as well. We estimate emissions in the counterfactual scenarios for SO_2, BC, and OC, we do so in two steps.

First, we estimate the emissions factor for the energy sector for the year before the policies to control air pollutants from coal-fired power plants became effective. We calculate the emissions factor as the emission estimates divided by the energy consumption at a regional level for the 22 provinces, 4 municipalities and 5 autonomous regions for 2005; see Equation (A1). We use province-level data on *Fuel use for power generation* as a driver of emissions from the energy sector (Fridley *et al.*, 2016). Because the Chinese National Bureau of Statistics does not report energy consumption data for Tibet but it does report thermal power generation, we use the last as a driver for the energy sector. We convert thermal power generation (TWh) into the units given for fuel use (million tonnes of coal equivalent, Mtce), multiplying TWh by the yearly average heat rates for fossil fuel-fired power plants depending on their average fuel consumption (Fridley *et al.*, 2016). This assumption does not significantly influence the results, because thermal power generation in Tibet is very low.

$$\boldsymbol{EF_{power\ (i)}} = \frac{\boldsymbol{E'_{power\ (i,2005)}}}{\boldsymbol{EC_{power(i,2005)}}} \tag{A1}$$

Second, we estimate the emissions for the *Energy counterfactual* scenario by multiplying the emission factor at the province-level by the province-level *Fuel use for power generation* ($Mtce_{2006\text{-}2014}$); see Equation (A2).

$$\boldsymbol{E_{power\ (i,j)}} = \boldsymbol{EC_{power\ (i,j)}} \times \boldsymbol{EF_{power\ (i)}} \tag{A2}$$

where $E'_{power\ (I,\ 2005)}$ is the actual emissions (Mt) in province i for year 2005, $EC_{power\ (I,\ 2005)}$ is the fuel use for power generation (Mtce) in province i for 2005, $E_{power\ (I,\ j)}$ is the emissions (Mt) at province (i) for year (j), $EC_{power\ (I,\ j)}$ is the fuel use for power generation (Mtce) at province (i) for year j, and $EF_{power\ (i)}$ is the emission factor (Mt/Mtce) in province i for 2005.

We calculate the emissions for the *Industry counterfactual* scenario as described in Equation (A3). We use province-level data on *Industrial sector end use* (Fridley *et al.*, 2016) as a driver of emissions from industry. The data on *Industrial sector end use* are given as coal, petroleum, and electricity consumption. We convert the coal and petroleum consumption given in Mt into Mtce, using the same procedure as described for the energy sector.

$$\boldsymbol{E_{industry(i,j)}} = \frac{\boldsymbol{E'_{industry\ (i,j)}}}{\frac{\boldsymbol{E_{power\ (i,j)}}}{\boldsymbol{E'_{power\ (i,j)}}}} \tag{A3}$$

where $E_{industry\ (I,\ j)}$ is the emissions (Mt) in province i for year j, $E'_{industry}$ is the actual emissions (Mt) in province i for year j, $E_{power\ (I,j)}$ is from Equation (A2), and $E'_{power\ (I,j)}$ is the actual emissions (Mt) in province i for year j.

A5 Pollutants by sector

Table D Pollutants from the energy, industrial, residential and commercial, and transport sectors in China for 2014. Reactive gas: sulfur dioxide (SO_2), and carbonaceous aerosols: black carbon (BC) and organic carbon (OC). Units: kilotonnes (kt) (Hoesly *et al.*, 2017).

Sectors	**Pollutants, kt**		
Energy	**SO_2**	**BC**	**OC**
Combustions emissions			
Electricity public and auto-producer	5,596	63	139
Heat production	1,956	7	16
Transformation (e.g., fuel combustion in coal coke production, oil refining, charcoal production)	1,998	712	1,187
Non-combustions emissions			
Fugitive petroleum and gas	0	3	1
Fossil-fuel fires	199	0	0
Sub-total:	**9,749**	**785**	**1,343**
Industry			
Combustions emissions			
Iron and steel	3,143	38	29
Non-ferrous metals	371	5	4
Chemicals	2,369	30	22
Pulp and paper	543	7	5
Food and tobacco	822	11	8
Non-metallic minerals	6,781	83	61
Construction	21	14	5
Machinery	361	8	4
Mining and quarrying	227	10	4
Other	656	7	4
Textile leather	419	6	4
Transport equipment	166	4	2
Wood products	119	2	1
Non-combustions emissions			
Chemical industry	262	0	0
Metal production	5,090	0	0
Pulp and paper. Food and beverage. Wood	304	0	0
Sub-total:	**21,654**	**225**	**152**
Residential and Commercial			
Combustions emissions			
Commercial-institutional	925	95	108
Residential	3,226	823	1,810
Agriculture, forestry and fishing	762	79	83
Other	771	54	70
Sub-total:	**5,684**	**1,051**	**2,071**
Transport			

Combustions emissions			
Road	41	206	86
Rail	8	16	4
Domestic navigation	179	12	9
Other	7	2	1
Sub-total:	**235**	**237**	**100**
Total:	**37,322**	**2,299**	**3,666**

A6 Installed solar PV capacities

Table E Historical cumulative installed solar PV capacities (MW) by province and region (Bloomberg NEF, 2017).

Region	Province	2010	21011	2012	2013	2014	2015	2016
East	Anhui	7	7	42	209	580	1'745	4'876
	Fujian	6	11	37	59	114	168	208
	Jiangsu	90	388	492	1'524	2'586	3'763	4'930
	Jiangxi	10	16	65	116	155	442	1'737
	Shandong	59	176	259	530	819	2'020	3'732
	Shanghai	19	16	24	193	228	319	348
	Zhejiang	10	31	111	370	828	1'674	3'704
	Subtotal:	**200**	**645**	**1'030**	**3'001**	**5'310**	**10'132**	**19'535**
North	Beijing	4	22	73	130	195	197	197
	Hebei	6	55	99	489	1'083	2'454	4'423
	Inner Mongolia	13	128	335	1'371	3'380	5'293	7'023
	Shanxi	10	34	49	227	563	1'231	3'387
	Tianjin	5	19	21	99	134	191	412
	Subtotal:	**38**	**258**	**576**	**2'316**	**5'354**	**9'366**	**15'441**
NorthEast	Heilongjiang	-	30	56	68	78	148	209
	Jilin	2	2	2	72	77	180	643
	Liaoning	0	33	46	94	114	185	505
	Subtotal:	**2**	**65**	**104**	**234**	**268**	**513**	**1'357**
NorthWest	Gansu	16	253	960	4'487	6'358	7'141	7'561
	Ningxia	96	410	593	1'493	2'223	3'549	4'360
	Qinghai	65	901	1'427	3'710	5'222	6'086	6'768
	Shaanxi	9	38	87	248	811	1'478	2'977
	Xinjiang	-	102	453	3'307	4'169	6'529	8'515
	Subtotal:	**186**	**1'704**	**3'520**	**13'244**	**18'784**	**24'784**	**30'181**
SouthCentral	Guangdong	20	32	104	279	523	893	1'396
	Guangxi	-	1	1	21	30	160	231
	Hainan	-	20	54	137	207	277	289
	Henan	3	15	52	127	523	813	3'236
	Hubei	9	16	30	96	138	1'153	2'008
	Hunan	5	38	60	138	256	373	491
	Subtotal:	**37**	**122**	**300**	**798**	**1'677**	**3'670**	**7'651**
SouthWest	Chongqing	-	-	-	-	-	-	10
	Guizhou	-	-	-	-	-	50	320
	Sichuan	11	11	14	76	126	456	903
	Tibet	10	90	154	208	228	288	361
	Yunnan	92	178	220	340	555	1'854	2'581
	Subtotal:	**114**	**279**	**388**	**624**	**909**	**2'648**	**4'174**
	Total:	**577**	**3'073**	**5'919**	**20'217**	**32'302**	**51'112**	**78'341**

A7 Correction factors on solar PV generation

Table F Correction factors on the annual electricity generation solar for optimal panel orientation and tilt for each province. Values obtained from CM SAF SARAH solar radiation data set (JRC, 2017). Some provinces fall out of the range of the satellites; hence, we assign to the provinces marked with (*) the correction factors of the neighbor Anhui and with (**) of the neighbor Beijing.

Province	Correction factor	Province	Correction factor
East		**Nord-West**	
Anhui	1.072	Gansu	1.196
Fujian	1.044	Ningxia	1.187
Jiangsu	1.089	Qinghai	1.146
Jiangxi	1.032	Shaanxi	1.126
Shandong	1.122	Xinjiang	1.197
Shanghai*	1.072	**South-Central**	
Zhejiang*	1.072	Guangdong	1.048
Nord		Guangxi	1.029
Beijing	1.174	Hainan	1.014
Hebei	1.154	Henan	1.086
Inner Mongolia	1.219	Hubei	1.053
Shanxi	1.162	Hunan	1.032
Tianjin	1.154	**Nord-West**	
Nord-East		Chongqing	1.026
Heilongjiang**	1.174	Guizhou	1.026
Jilin**	1.174	Sichuan	1.037
Liaoning**	1.174	Tibet	1.163
		Yunnan	1.084

A8 Feed-in tariff schemes

Table G shows the various feed-in tariffs (FiTs) schemes for on-grid solar photovoltaic (PV) projects in China over the years. As specified by the *Renewable Energy Law of the People's Republic of China*, since 2009, there has been an indemnificatory purchasing system in place for solar power generation. To determine the acceptable level of FiT, project tenders were invited in two rounds: the first in 2009, for a 20 MW project in the province of Gansu; the second in 2010, for a group of projects totaling 280 MW in Shaanxi, Qinghai, Inner Mongolia, and Ningxia. In 2011, the National Development and Reform Commission (NDRC) issued the *Notice on Perfecting a Feed-in Tariff Policy of Solar Energy PV Power Generation*, which determined the benchmark for the first nationwide, unified FiT. That FiT did not account for the differences in solar radiation across China. Hence, solar projects' owners focused on the installation of solar PV plants in western China, where energy demand is lower due to lower population density and economic development. To address this mismatch, in 2013, the NDRC issued the *Notice on Promoting the Healthy Development of the Solar PV Industry through the Price Leverage Effect*, dividing the FiT into three different compensation levels depending on solar resources and construction costs (NDRC, 2013); see Table H. The FiT was further reduced for those projects registered after the beginning of 2016.

Table G Feed-in tariffs for solar PV projects (RMB /kWh, including tax), rates over the years (NDRC, 2013, 2016; Pegels, 2014; Sun *et al.*, 2014; Ye Qi, 2013).

2009[1]	**2010**[2]	**2011**[3]	**2012**[3]	**2013**	**Resource area**	**2014**[4]	**2016**[5]	**2017**[6]
1.09	1.15; 0.73-0.99	1.15	1.00	1.00	Area I	0.90	0.8	0.65
					Area II	0.95	0.88	0.75
					Area III	1.00	0.98	0.85

[1] The feed-in tariff (FiT) for selected project applies since March 2009.

[2] The FiT for the projects in Ningxia was RMB1.15 /kWh, in April 2010. The FiT for the projects in Shaanxi, Qinghai, Inner Mongolia and Ningxia was RMB0.73 /kWh for the lowest, while RMB 0.99 /kWh for the highest, in June 2010.

[3] Nationwide FiT of RMB1.15 /KWh for projects completed and put into operation prior to December 31, 2011, and of RMB1.0 /KWh after that day in every province except Tibet, which enjoys the right to employ the former FiT.

[4] The FiT apply to projects registered after September 1, 2013. Projects that were registered before that date, but started generation after January 1, 2014, were also eligible for the subsidies. Tibet employ the FiT of RMB1.0 /KWh.

[5] The FiT apply to projects registered after January 1, 2016. Tibet employ the FiT of RMB1.0 /KWh.

[6] The FiT apply to projects registered after January 1, 2017. Tibet employ the FiT of RMB1.0 /KWh.

Table H Chinese regions within each the three resource areas (NDRC, 2013).

Resource area	**Regions within resource area**
Area I	Ningxia (Ningxia Autonomous Region); Haixi (Qinghai Province); Jiayuguan, Wuwei, Zhangye, Jiuquan, Dunhuang, Jinchang (Gansu Province); Hami, Tacheng, Altay, Karamay (Xinjiang Autonomous Region); areas in Inner Mongolia other than Chifeng, Tongliao, Xing'anmeng and Hulunbeier.
Area II	Beijing (Beijing Municipality); Tianjin (Tianjin Municipality); Heilongjiang (Heilongjiang Province); Jilin (Jilin Province); Liaoning (Liaoning Province); Sichuan (Sichuan Province); Yunnan (Yunnan Province); Chifeng, Tongliao, Xing'anmeng and Hulunbeier (Inner Mongolia Autonomous Region); Chengde, Zhangjiakou, Tangshan and Qinhuangdao (Hebei Province); Datong, Shuozhou and Xinzhou (Shanxi Province); Yulin and Yan'an (Shaanxi Province), areas in Qinghai, Gansu and Xinjiang other than Resource Area I.
Area III	Areas other than areas in Resource Areas I-II, including Tibet autonomous region

Note: Regional solar resources as classified in class I, II or III in descending order of solar endowment.

A9 Cost of implementing clean-air policies

Table I Annual costs (billion $) of implementing policies in a sectorial basis to reach near-zero emissions.

Sector and sub-sectors		Low estimate	High estimate
Energy			
	Combustion processes		
	Electricity generation	4.2	6.7
	Heat generation	1.5	2.3
	Non-combustion processes		
	Transformation	1.5	2.4
	Sub-total	**7.2**	**11.4**
Industry			
	Combustion processes	12.0	19.1
	Non-combustion processes	4.2	6.7
	Sub-total	**16.2**	**25.8**
RCO			
	Combustion processes		
	Residential rural	6.5	10.6
	Residential urban	1.2	1.9
	Commercial	2.2	3.6
	Sub-total	**9.9**	**16.1**
Transport			
	Combustion processes		
	Road transport (fuel)	4.3	
	Road transport (engine)	7.4	
	Domestic navigation	3.6	
	Sub-total	**15.3**	
Total		**48.6**	**68.6**

A10 Effect of counterfactual and potential clean-air policies on surface solar irradiance: nationwide

A10.1 Effect of past and counterfactual clean-air policies on surface solar irradiance

Here we show the effect of past and counterfactual air pollution control measures on surface solar irradiance. In the energy sector, China has made strong progress, and visibility is better than it would have been without past and existing measures. Figure Ba shows the effect of the SO_2 control measures and the removal of carbonaceous particles in the energy sector since 2006, i.e., moving from *Energy counterfactual* to *Energy actual*, which have increased surface solar irradiance by up to 3.5% (5 W/m^2). Applying the same emission standards to industry as already exist for energy, i.e., reducing emissions from *Industry actual* to *Industry counterfactual*, would increase surface solar irradiance by up to 2.2% (1.2 W/m^2). If we assume that state-of-the-art pollution control with full coverage is applied in the energy sector, and that this "near-zero" emission technology will fully eliminate all aerosol emissions (i.e., from *energy actual* to zero), the irradiance would increase by up to 6% (10 W/m^2), showing that although much has been achieved in the energy sector, there is still much room for further improvement. Overall, the effect of pollution control on solar irradiance is large: eliminating all energy and industry emissions from unabated levels (*energy counterfactual* and *industry actual*), assuming no control measures since 2006, increases irradiance by up to 13.5% (16 W/m^2; Figure Ca-d for results expressed in W/m^2 irradiance increase).

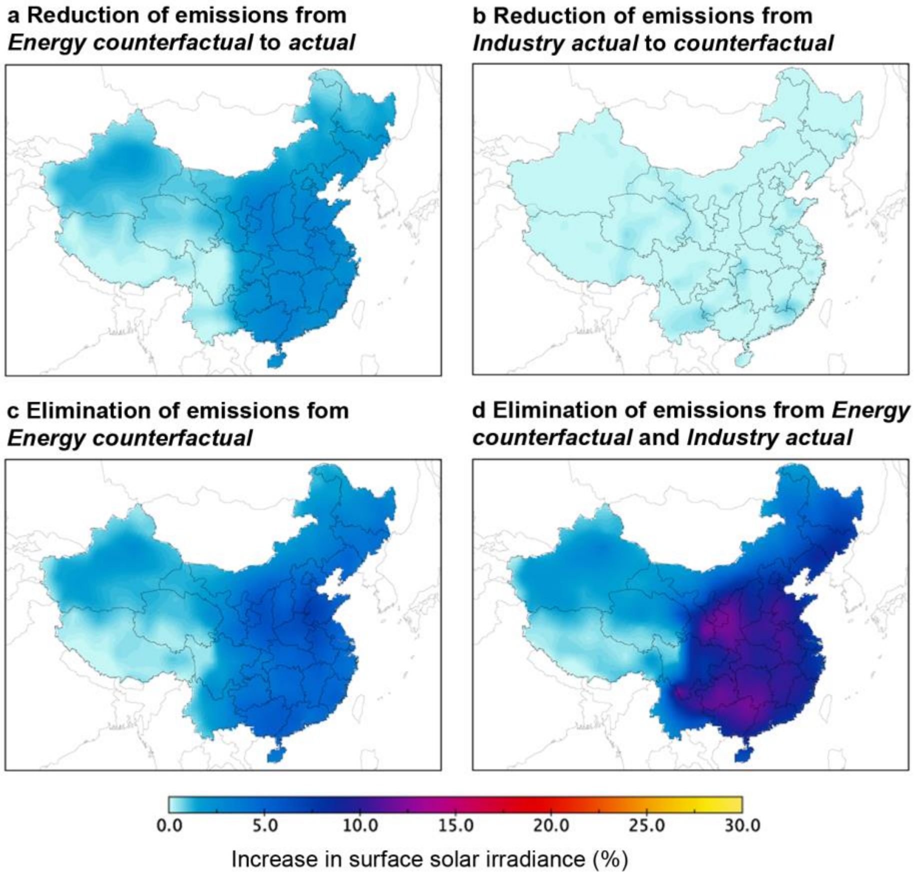

Figure B Increase in surface solar irradiance in percent (%). From an emission abatement of SO_2, BC, and OC emission from energy counterfactual to energy actual (a), from industry actual to industry counterfactual (b), from an elimination of emissions from energy counterfactual (c), and an elimination of emissions from energy counterfactual and industry actual (d). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

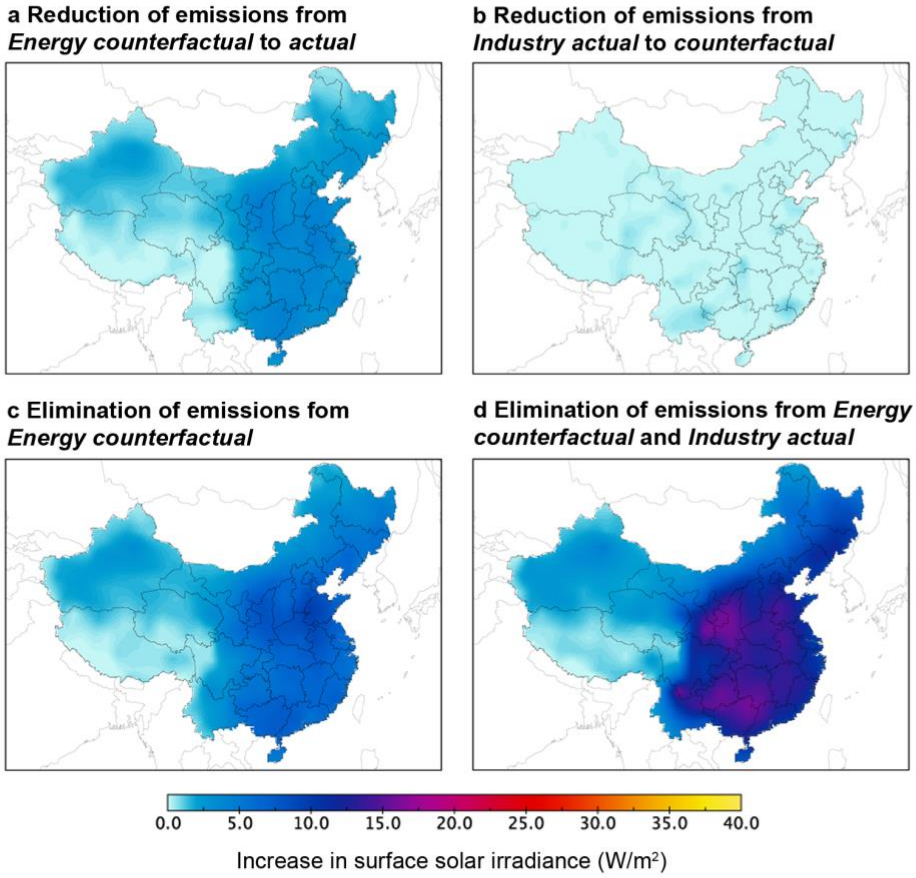

Figure C Increase in surface solar irradiance (W/m^2). From an emission abatement of BC, OC and SO_2 from energy counterfactual to energy actual (a), from industry actual to industry counterfactual (b), from an elimination of emissions from energy counterfactual (c), and an elimination of emissions both from energy counterfactual and industry actual (d). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

A10.2 Effect of potential clean-air policies on surface solar irradiance

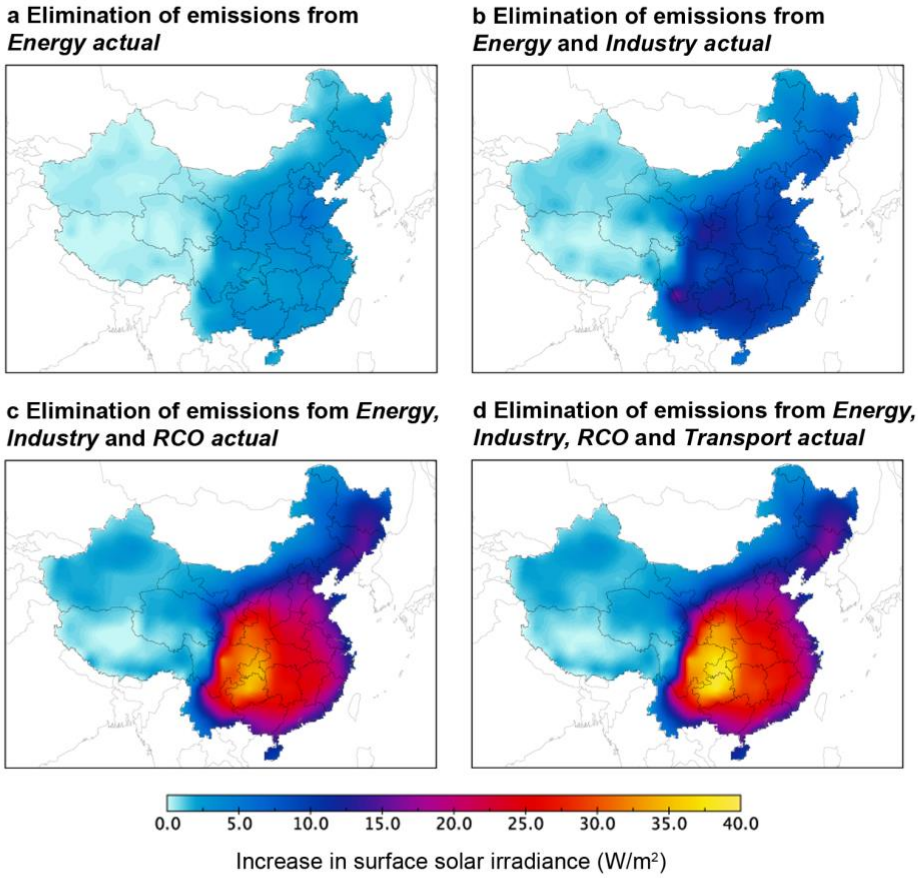

Figure D Increase in surface solar irradiance (W/m^2). From an elimination of actual BC, OC and SO_2 emissions from energy sector (a), of actual emissions from energy and industrial sectors (b), of actual emissions from energy, industrial and residential and commercial (RCO) sectors (c), and of actual emissions from energy, industrial, RCO, and transport sectors (d). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

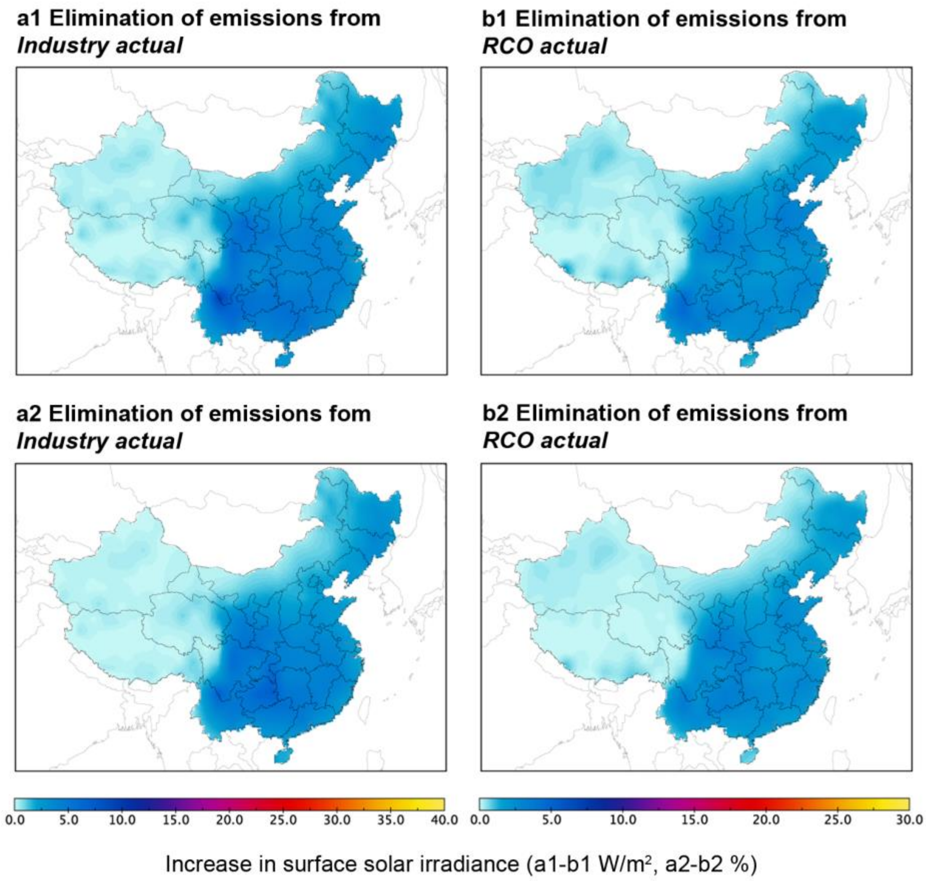

Figure E Increase in surface solar irradiance (W/m^2, %). From an elimination of actual BC, OC and SO_2 emissions from industrial sector (a), and an elimination of actual emissions from residential and commercial (RCO) sector (b). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

A10. 3 Effect of potential clean-air policies for SO_2 on surface solar irradiance

The solar radiation benefits of eliminating all current, actual emissions will be greater than if the focus were on eliminating SO_2 emissions only: eliminating all emissions in the energy sector increases surface radiation by up to 6 W/m^2, as compared to the increase of 2.4 W/m^2 seen when eliminating only SO_2 (Figure Fa-d). The irradiation gains from eliminating all emissions in the energy and industrial sectors is 16.8 W/m^2, as compared to the 14.4 W/m^2 from eliminating only SO_2. Also, the irradiation gains from eliminating all emissions in the energy, industrial and RCO sectors is 35.6 W/m^2, as compared to the 21.5 W/m^2 from eliminating SO_2.

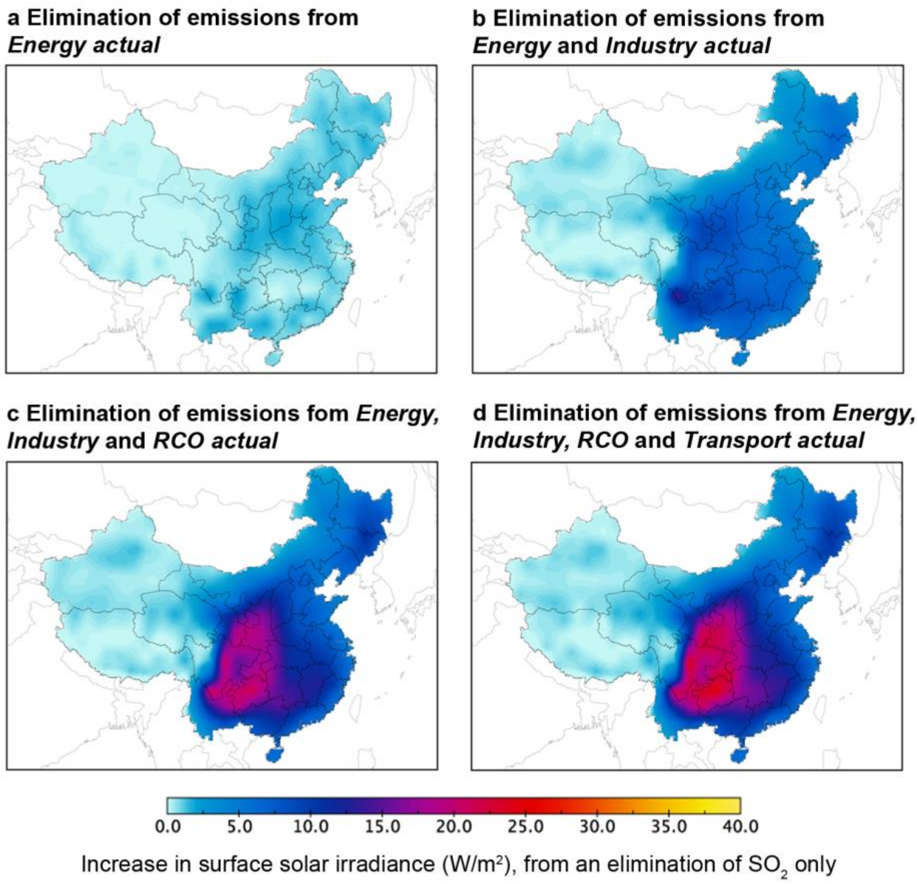

Figure F Increase in surface solar irradiance (W/m^2). From an elimination of actual SO_2 emissions from energy sector (a), of actual emissions from energy and industrial sectors (b), of actual emissions from energy, industrial and residential and commercial (RCO) sectors (c), and of actual emissions from energy, industrial, RCO, and transport sectors (d). Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

The solar radiation benefits of eliminating all aerosol emissions in the energy sector compared to eliminating in the same sector only SO_2 emissions (3.6 W/m^2) are greater than for the energy and industrial sectors combined (2.4 W/m^2). This non-linear increase in surface solar radiation is due to the relative amount of SO_2 emissions per sector compared to total emissions. As seen in Table D, the ratio of SO_2 emissions to total emissions in the energy and industrial sectors combined (0.98) is larger than in the energy sector alone (0.82). Thus, for the energy and industrial sectors combined, eliminating only SO_2 emissions is closer to eliminating all aerosol emissions than for the energy sector alone. Also, there is no one-to-one correspondence between the ratio of "SO_2 emissions to all emissions" and of "SO_2 induced irradiance reductions to irradiance reductions from all emissions" because the model computes effects of, e.g., aerosol mixing, aerosol cloud interactions, and different transport and deposition properties.

A11 Province-specific increases in surface solar irradiance

Table J Mean province-specific increases in solar surface irradiance (W/m^2) and its corresponding increases in solar electricity generation (GWh per year) for the operational grid-connected solar PV installations as of December 2016, for an elimination of actual SO_2, BC and OC emissions from a number of emission reduction strategies on different combinations of sectors. The means are area-weighted means.

	Increase in solar surface irradiance					Increase in solar electricity generation
Province	**Energy**	**Energy, Industry**	**Energy, Industry, Transport**	**Energy, Industry RCO**	**All sectors**	**All sectors**
Anhui	3.7	9.2	10.4	20.4	23.0	897.5
Beijing	3.2	8.0	8.7	15.1	16.2	28.2
Chongqing	3.2	10.0	10.8	33.4	37.0	2.8
Fujian	3.2	8.5	9.2	17.8	19.4	31.4
Gansu	3.3	5.7	5.9	11.0	11.6	786.0
Guangdong	2.9	8.9	9.5	17.7	18.7	203.9
Guangxi	2.9	10.0	10.6	20.7	22.0	38.9
Guizhou	2.4	11.6	12.3	31.0	33.7	82.4
Hainan	2.6	5.8	6.2	10.7	11.5	25.1
Hebei	1.7	7.7	8.7	14.4	15.6	600.8
Heilongjiang	3.1	5.0	5.3	9.1	9.4	17.1
Henan	2.7	9.8	10.9	22.7	25.7	671.4
Hubei	1.3	9.7	11.0	26.1	29.3	462.1
Hunan	2.2	10.3	11.5	26.5	29.2	97.9
Inner Mongolia	2.5	3.8	8.7	16.0	6.7	426.3
Jiangsu	1.6	8.0	10.9	23.3	17.8	713.6
Jiangxi	3.0	9.7	7.5	12.5	25.6	341.8
Jilin	0.8	7.2	7.8	12.9	13.3	70.3
Liaoning	3.4	7.6	4.1	6.3	13.6	60.3

Ningxia	1.2	9.7	10.0	18.7	19.7	768.8
Qinghai	3.1	1.5	1.7	2.4	2.5	146.0
Shaanxi	3.3	10.8	11.5	26.2	28.8	718.5
Shandong	2.8	8.8	9.9	16.5	18.0	557.4
Shanghai	3.5	6.4	6.7	11.6	13.0	36.6
Shanxi	3.2	8.7	9.4	18.4	20.2	602.2
Sichuan	3.3	7.4	7.7	18.4	19.9	132.9
Tianjin	2.7	8.3	9.2	15.1	16.0	56.5
Tibet	2.6	0.6	0.9	1.6	0.9	2.8
Xinjiang	0.7	1.6	0.6	0.8	1.7	128.7
Yunnan	0.3	7.7	7.9	14.3	14.8	308.7
Zhejiang	0.5	7.6	8.1	16.0	17.5	519.9
Country-wide	**1.7**	**4.8**	**5.2**	**10.1**	**10.9**	**9'537**

A12 Increase in solar generation

Table K Increase in solar generation (TWh) from an elimination of emissions from a specific sector or a combination of them, for projected installed PV capacities for 2020, 2030 and 2040, the last two for a low and a high PV capacity scenario.

	Elimination of emissions			
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Low capacity scenario				
2020, 200 GW	24.3	22.3	11.0	3.9
2030, 400 GW	48.6	44.6	22.0	7.8
2040, 700 GW	85.0	78.0	38.5	13.6
High capacity scenario				
2020, 200 GW	24.3	22.3	11.0	3.9
2030, 600 GW	72.9	66.9	33.0	11.7
2040, 1300 GW	157.9	144.9	71.6	25.3

A13 Total revenues from increase in solar generation

Table L Total annual revenues (billion $, discounted) leveraged from the feed-in tariff on the increase in solar power, for feed-in tariffs that reduce over time as the national PV system cost reduces following a technological learning rate of 20% starting in 2017, i.e., the year of the last available feed-in tariffs, for feed-in tariffs without technological learning, i.e., equal to the feed-in tariffs in 2017, and for projected installed PV capacities for 2020, 2030 and 2040, the last two for a low and a high PV capacity scenario. Revenues discounted to the present using a discount rate of 5% and 8% (*).

Increased annual revenues in the solar sector from elimination of sectoral emissions				
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 0%				
Low PV capacity scenario				
2020, 200 GW	2.9 – 2.8*	2.6 – 2.6*	1.3 – 1.3*	0.5 – 0.5*
2030, 400 GW	4.6 – 4.1*	4.2 – 3.8*	2.1 – 1.9*	0.8 – 0.7*
2040, 700 GW	6.2 – 5.1*	5.7 – 4.7*	2.8 – 2.3*	1.0 – 0.8*
High PV capacity scenario				
2020, 200 GW	2.9 – 2.8*	2.6 – 2.6*	1.3 – 1.3*	0.5 – 0.5*
2030, 600 GW	6.4 – 5.5*	5.9 – 5.0*	2.9 – 2.5*	1.1 – 0.9*
2040, 1300 GW	10.1 – 7.7*	9.3 – 7.1*	4.6 – 3.5*	1.7 – 1.3*
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 20%				
Low PV capacity scenario				
2020, 200 GW	2.7 – 2.6*	2.5 – 2.4*	1.2 – 1.2*	0.5 – 0.5*
2030, 400 GW	3.9 – 3.6*	3.6 – 3.3*	1.8 – 1.6*	0.7 – 0.6*
2040, 700 GW	4.9 – 4.1*	4.4 – 3.8*	2.2 – 1.9*	0.8 – 0.7*
High PV capacity scenario				
2020, 200 GW	2.7 – 2.6*	2.5 – 2.4*	1.2 – 1.2*	0.5 – 0.5*
2030, 600 GW	5.1 – 4.5*	4.7 – 4.1*	2.3 – 2.0*	0.8 – 0.8*
2040, 1300 GW	6.9 – 5.6*	6.4 – 5.1*	3.3 – 2.6*	1.2 – 1.0*

Table M Total annual revenues (billion $, undiscounted) leveraged from the feed-in tariff on the increase in solar power, for feed-in tariffs that reduce over time as the national PV system cost reduces following a technological learning rate of 20% starting in 2017, i.e., the year of the last available feed-in tariffs, for feed-in tariffs without technological learning, i.e., equal to the feed-in tariffs in 2017, and for projected installed PV capacities for 2020, 2030 and 2040, the last two for a low and a high PV capacity scenario.

Increased annual revenues in the solar sector from elimination of sectoral emissions				
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 0%				
Low PV capacity scenario				
2020, 200 GW	3.1	2.8	1.4	0.5
2030, 400 GW	5.8	5.3	2.6	1.0
2040, 700 GW	9.9	9.1	4.5	1.6
High PV capacity scenario				
2020, 200 GW	3.1	2.8	1.4	0.5
2030, 600 GW	8.6	7.9	3.9	1.4
2040, 1300 GW	18.2	16.7	8.2	2.9
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 20%				
Low PV capacity scenario				
2020, 200 GW	2.9	2.7	1.3	0.5
2030, 400 GW	4.7	4.3	2.1	0.8
2040, 700 GW	7.1	6.5	3.2	1.2
High PV capacity scenario				
2020, 200 GW	2.9	2.7	1.3	0.5
2030, 600 GW	6.5	6.0	3.0	1.1
2040, 1300 GW	11.2	10.3	5.5	2.0

Table N Net present value (NPV) (billion $) for costs of policies to reach near-zero emissions (low estimate) and for discounted revenues. Revenues discounted to the present using a discount rate of 5% and 8% (*). A positive value means a net cost of the sectoral policy.

NPV of sectoral emission elimination policies				
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 0%				
Low PV capacity scenario				
2020, 200 GW	45.7 – 45.8*	30.8 – 30.9*	22.1 – 22.1*	6.7 – 6.7*
2030, 400 GW	44.0 – 44.5*	29.7 – 30.0*	21.3 – 21.5*	6.4 – 6.5*
2040, 700 GW	42.4 – 43.5*	28.9 – 29.5*	20.6 – 21.1*	6.2 – 6.4*
High PV capacity scenario				
2020, 200 GW	45.7 – 45.8*	30.8 – 30.9*	22.1 – 22.1*	6.7 – 6.7*
2030, 600 GW	42.2 – 43.1*	28.6 – 29.2*	20.5 – 20.9*	6.1 – 6.3*
2040, 1300 GW	38.5 – 40.9*	26.9 – 28.2*	18.8 – 19.9*	5.5 – 5.9*
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 20%				
Low PV capacity scenario				
2020, 200 GW	45.9 – 46.0*	30.8 – 30.9*	22.2 – 22.2*	6.7 – 6.7*
2030, 400 GW	44.7 – 45.0*	29.7 – 30.0*	21.6 – 21.8*	6.5 – 6.6*
2040, 700 GW	43.7 – 44.5*	28.9 – 29.5*	21.1 – 21.5*	6.4 – 6.5*
High PV capacity scenario				
2020, 200 GW	45.9 – 46.0*	30.8 – 30.9*	22.2 – 22.2*	6.7 – 6.7*
2030, 600 GW	43.5 – 44.1*	28.6 – 29.2*	21.1 – 21.4*	6.4 – 6.4*
2040, 1300 GW	41.7 – 43.0*	26.9 – 28.2*	20.1 – 20.8*	6.0 – 6.2*

Table O Net present value (NPV) (billion $) for costs of policies to reach near-zero emissions (high estimate) and for discounted revenues. Revenues discounted to the present using a discount rate of 5% and 8% (*). A positive value means a net cost of the sectoral policy.

NPV of sectoral emission elimination policies				
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 0%				
Low PV capacity scenario				
2020, 200 GW	65.7 – 65.8*	50.7 – 50.7*	35.9 – 35.9*	10.9 – 10.9*
2030, 400 GW	64.0 – 64.5*	49.1 – 49.5*	35.1 – 35.3*	10.6 – 10.7*
2040, 700 GW	62.4 – 63.5*	47.6 – 48.6*	34.4 – 34.9*	10.4 – 10.6*
High PV capacity scenario				
2020, 200 GW	65.7 – 65.8*	50.7 – 50.7*	35.9 – 35.9*	10.9 – 10.9*
2030, 600 GW	62.2 – 63.1*	47.4 – 48.3*	34.3 – 34.7*	10.3 – 10.5*
2040, 1300 GW	58.5 – 60.9*	44.0 – 46.2*	32.6 – 33.7*	9.7 – 10.1*
	Energy, Industry, RCO and transport	**Energy, Industry and RCO**	**Energy and Industry**	**Energy**
Learning rate 20%				
Low PV capacity scenario				
2020, 200 GW	65.9 – 66.0*	50.8 – 50.9*	36.0 – 36.0*	10.9 – 10.9*
2030, 400 GW	64.7 – 65.0*	49.7 – 50.0*	35.4 – 35.6*	10.7 – 10.8*
2040, 700 GW	63.7 – 64.5*	48.9 – 49.5*	35.0 – 35.3*	10.6 – 10.7*
High PV capacity scenario				
2020, 200 GW	65.9 – 66.0*	50.8 – 50.9*	36.0 – 36.0*	10.9 – 10.9*
2030, 600 GW	63.5 – 64.1*	48.6 – 49.2*	34.9 – 35.2*	10.6 – 10.6*
2040, 1300 GW	61.7 – 63.0*	46.9 – 48.2*	33.9 – 34.6*	10.2 – 10.4*

A14 Additional results

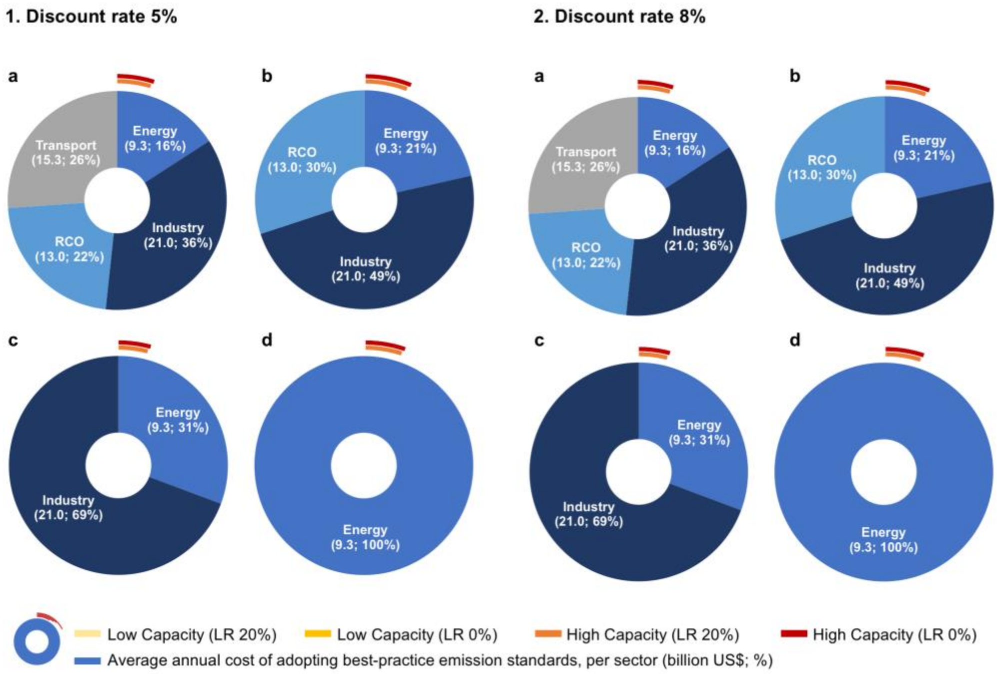

Figure G-1 and G-2 Annual average cost (billion $ and %) of adopting best-practice emission standards. To all sectors (a), the energy, industrial and residential and commercial (RCO) sectors (b), the energy and industrial sectors (c), and the energy sector alone (d), compared to the annual revenues (billion $, discounted) leveraged from the feed-in tariff on the Chinese PV fleet in 2020 of 200 GW, for a feed-in tariff that reduces over time as the national PV system cost reduces following a technological learning rate of 20% starting in 2017, i.e., the year of the last available feed-in tariffs, and for a feed-in tariff without technological learning, i.e., equal to the feed-in tariffs in 2017. Revenues discounted to the present using a discount rate of 5% and 8%. Sector-specific annual costs are averages of a low and a high cost scenario, for a break-d own of sub-sector-specific costs and uncertainty ranges see Table I. Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

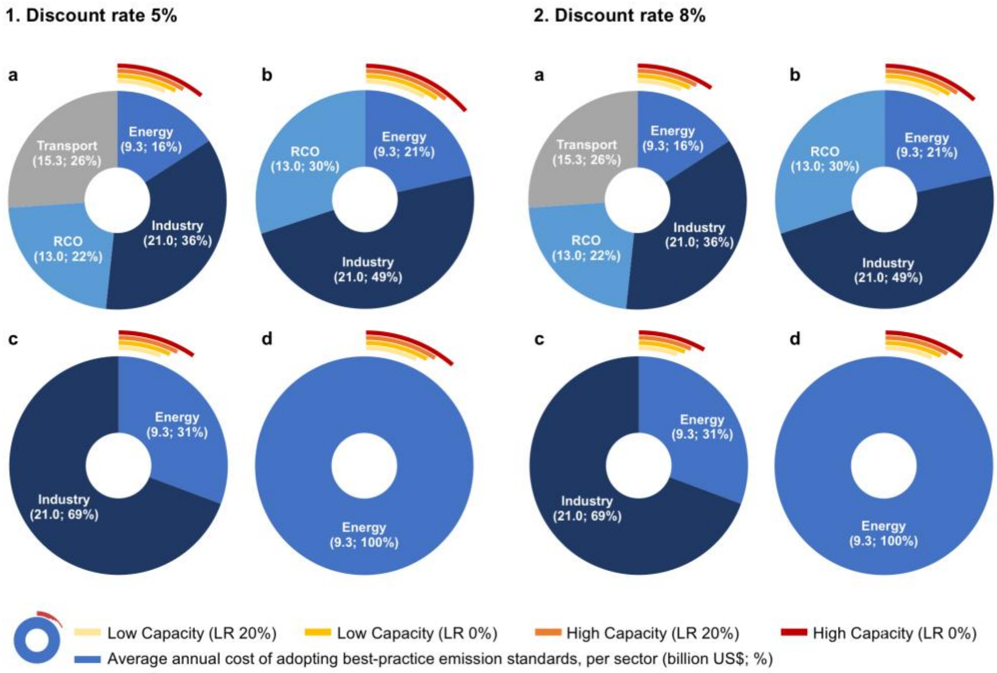

Figure H-1 and H-2 Annual average cost (billion $ and %) of adopting best-practice emission standards. To all sectors (a), the energy, industrial and residential and commercial (RCO) sectors (b), the energy and industrial sectors (c), and the energy sector alone (d), compared to the annual revenues (billion $, discounted) leveraged from the feed-in tariff on the Chinese PV fleet in 2030 for a low (400 GW) and a high capacity scenario (600 GW), and for a feed-in tariff that reduces over time as the national PV system cost reduces following a technological learning rate of 20% starting in 2017, i.e., the year of the last available feed-in tariffs, and for a feed-in tariff without technological learning, i.e., equal to the feed-in tariffs in 2017. Revenues discounted to the present using a discount rate of 5% and 8%. Sector-specific annual costs are averages of a low and a high cost scenario, for a break-down of sub-sector-specific costs and uncertainty ranges see Table I. Data and material from (Hoesly *et al.*, 2017; Stevens *et al.*, 2013; Stier *et al.*, 2005; Zhang *et al.*, 2012).

Appendix B: Supporting Information for Contribution III

Model description

B1 Model structure

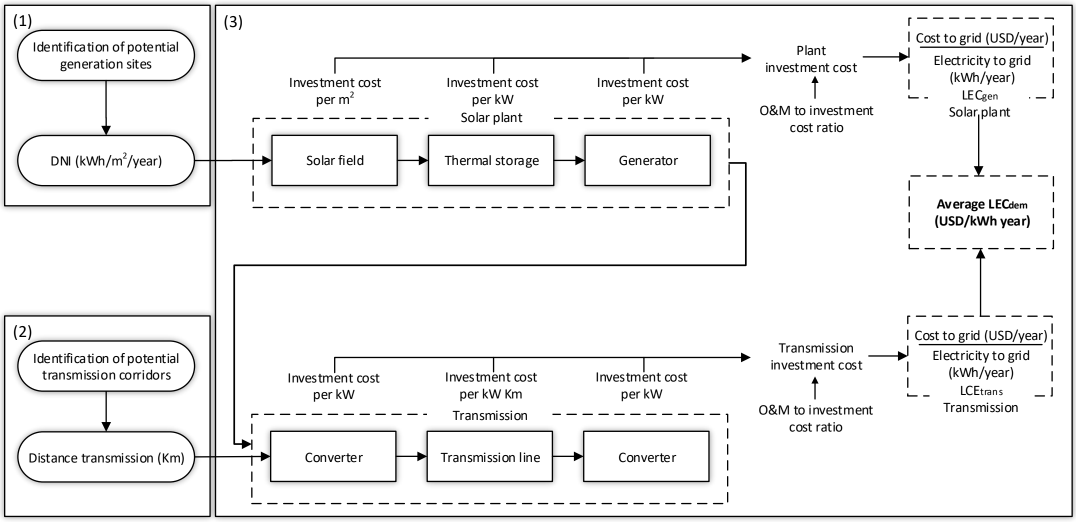

Figure A Model structure. The model is composed by three main sets of tools for: (1) identification of potential generation sites, (2) identification of potential transmission corridors and, (3) estimation of the solar electricity cost at the point of demand. Each of the solid boxes represents a specific subset of infrastructure. Final outputs are total investment costs, total electricity to grid and annual average levelized electricity cost.

The detailed methodology description for the identification of potential generation sites and transmission corridors is described in section B2, the extensive breakdown of the data used as input is provided in section B3, whereas the methodology for the calculations of the levelized electricity cost at the points of demand is described in section B4.

B2 Identification of optimal generation sites and transmission corridors

We use a geographic information system (GIS) platform to identify the optimal CSP generation sites and the transmission corridors. Current literature does not denote a specific method to assess site suitability of a CSP plant and the associated transmission corridors. Most existing studies use an exclusion criteria approach (Broesamle *et al.*, 2001; Fluri, 2009; Gastli *et al.*, 2010; Mehos and Kearney, 2007; Trieb *et al.*, 2009a). This results in an exclusion mask of non-suitable areas for CSP location, which is subsequently overlaid on a map of all areas with sufficient direct normal irradiance. Other studies have employed a weighting criterion for the different variables that determine CSP location (Clifton and Boruff, 2010; Dawson and Schlyter, 2012; Figueira and Roy, 2002). This weighting criterion results in a ranking of the variables (e.g. type of land cover, type of land protection, slope of the terrain, proximity to infrastructure, degree of visibility, etc.) in terms of importance to assess the suitability of the land. These studies use different methods and assumptions depending on the scope of the investigation. Yet, sufficiently strong classification certainty to identify common criteria for suitability mapping was not found. To decrease the uncertainty given by the variability of weighting criteria for CSP site location, we rely on an excluding and non-excluding criteria approach to identify suited and unsuited CSP generation sites (see Table A1).

Table A Selected and excluded criteria for identification of CSP sites.

	Selected	Excluded	Considerations
Direct Normal Irradiance (DNI)			
DNI ≥ 2,000 kWh/m^2/year	x		
Slope			
Slope > 3%		x	
Land Cover			
Cropland, rain fed: Herbaceous cover	x		
Cropland, rain fed: Tree or shrub cover	x		
Cropland, irrigated or post-flooding	x		
Mosaic cropland (>50%) / natural vegetation (tree, shrub, herbaceous cover) (<50%)	x		
Mosaic natural vegetation (tree, shrub, herbaceous cover) (>50%) / cropland (<50%)	x		
Tree cover, broadleaved, evergreen, closed to open (>15%)	x		
Tree cover, broadleaved, deciduous, closed (>40%)	x		
Tree cover, broadleaved, deciduous, open (15-40%)	x		
Tree cover, needle leaved, evergreen, closed (>40%)	x		
Tree cover, needle leaved, evergreen, open (15-40%)	x		
Tree cover, needle leaved, deciduous, closed (>40%)	x		
Tree cover, needle leaved, deciduous, open (15-40%)	x		
Tree cover, mixed leaf type (broadleaved and needle leaved)	x		
Mosaic tree and shrub (>50%) / herbaceous cover (<50%)	x		
Mosaic herbaceous cover (>50%) / tree and shrub (<50%)	x		
Shrub land: Evergreen shrub land	x		
Shrub land: Deciduous shrub land	x		
Grassland	x		
Lichens and mosses	x		
Sparse shrub (<15%)	x		
Sparse herbaceous cover (<15%)	x		

Tree cover, flooded, fresh or brackish water		x	
Tree cover, flooded, saline water		x	
Shrub or herbaceous cover, flooded, fresh/saline/brackish water		x	
Bare areas: Consolidated bare areas	x		
Bare areas: Unconsolidated bare areas	x		
Bare areas: Sandy desert and dunes		x	Buffer 3km around shifting sands
Water bodies		x	
Permanent snow and ice		x	
Protected areas		x	Buffer 2 km around protected areas
Industrial locations and population			
Airports		x	Buffer 3 km around airports
Urban areas		x	

The identification of the transmission corridors relies on a weighting approach. Weights, here measured in terms of incremental installation costs over a base case of flat grassland, are assigned to the land to identify the least cost interconnection between the demand and the generation sites (see Table B). Incremental costs on land to deploy a transmission line vary widely depending on land cover typology. In the case of transmission lines crossing unstable ground, such as sandy ground, requires larger and deeper tower foundations to avoid subsidence during operation foundation. In this case, costs may increase by 24% to 48%, compared to drained arable land. For large river crossings, associated structures are needed, and the costs increase by 60% to 100% (Parsons Brinckerhoff, 2012). Incremental costs on land also vary widely depending on the slope of the terrain. When the transmission line crosses rolling hills and thus 3 m extra of tower height is typically required, costs typically increase by 5% compared to the base case of flat ground (Parsons Brinckerhoff, 2012). Extra additional expenditures are required to install transmission lines and associated pylons in slopes higher than 20% (Trieb *et al.*, 2009a). The range of slope values in degrees in GIS is 0 to 90 degrees. Whereas a flat surface corresponds to 0%, a 45-degree surface corresponds to 100%; as the surface becomes more vertical, the incline increases beyond 100%. Trieb *et al.* (2009a) assume that above 200%, the magnitude of the slope is irrelevant for the additional costs. Thus, here we keep the weight constant for slopes above this value.

Regarding the incremental costs on land cover, we assign a value of 1.0 for the base case of flat grassland up to a value of 7.0 depending on the typology of land (a value of 10,000 means non-suitable and thus excluded). Regarding the incremental costs on the incline of the terrain, we assign a value of 1.0 for slopes up to 20% and increase it linearly in steps of 45% up to a value of 10 for slopes of 200%. Then, we sum the weights on the land cover and on the slope of the terrain and identify the land representing the least cost interconnection.

Table B Weighting criteria for the evaluation of land for transmission corridors.

Land Cover	**Weight**
Cropland, rain fed: Herbaceous cover	1.0
Cropland, rain fed: Tree or shrub cover	1.0
Cropland, irrigated or post-flooding	1.0
Mosaic cropland (>50%) / natural vegetation (tree, shrub, herbaceous cover) (<50%)	1.0
Mosaic natural vegetation (tree, shrub, herbaceous cover) (>50%) / cropland (<50%)	1.0
Tree cover, broadleaved, evergreen, closed to open (>15%)	5.0
Tree cover, broadleaved, deciduous, closed (>40%)	5.0
Tree cover, broadleaved, deciduous, open (15-40%)	5.0
Tree cover, needle leaved, evergreen, closed (>40%)	5.0
Tree cover, needle leaved, evergreen, open (15-40%)	5.0
Tree cover, needle leaved, deciduous, closed (>40%)	5.0
Tree cover, needle leaved, deciduous, open (15-40%)	5.0
Tree cover, mixed leaf type (broadleaved and needle leaved)	5.0
Mosaic tree and shrub (>50%) / herbaceous cover (<50%)	1.0
Mosaic herbaceous cover (>50%) / tree and shrub (<50%)	1.0
Shrub land: Evergreen shrub land	1.0
Shrub land: Deciduous shrub land	1.0
Grassland	1.0
Lichens and mosses	1.0
Sparse shrub (<15%)	1.0
Sparse herbaceous cover (<15%)	1.0
Tree cover, flooded, fresh or brackish water	7.0
Tree cover, flooded, saline water	10,000
Shrub or herbaceous cover, flooded, fresh/saline/brackish water	10,000
Bare areas: Consolidated bare areas	1.0
Bare areas: Unconsolidated bare areas	3.0
Water bodies	7.0
Permanent snow and ice	10,000
Slope (%)	**Weight**
0-20	1.0
20-65	3.0
65-110	5.0
110-155	7.0
155-200	10.0
>200	10.0

B3 Data

Direct normal irradiance

Direct sunlight, as measured by the direct normal irradiance, is the fundamental resource for CSP technologies. It refers to the "radiation flux (irradiance) normal to the direction of the sun in the 0.2-4 µm wavelength region", at the ground surface (CM SAF, 2014). We use 31 years (1983-2013) of Climate Monitoring Satellite Application Facilities (CM-SAF) direct normal irradiance data at a resolution of 0.05° x 0.05° (Müller *et al.*, 2015). This dataset accurately represents the general structure of the spatial distribution of the surface solar radiation. The temporally averaged CM SAF direct normal irradiance dataset is shown in Figure B.

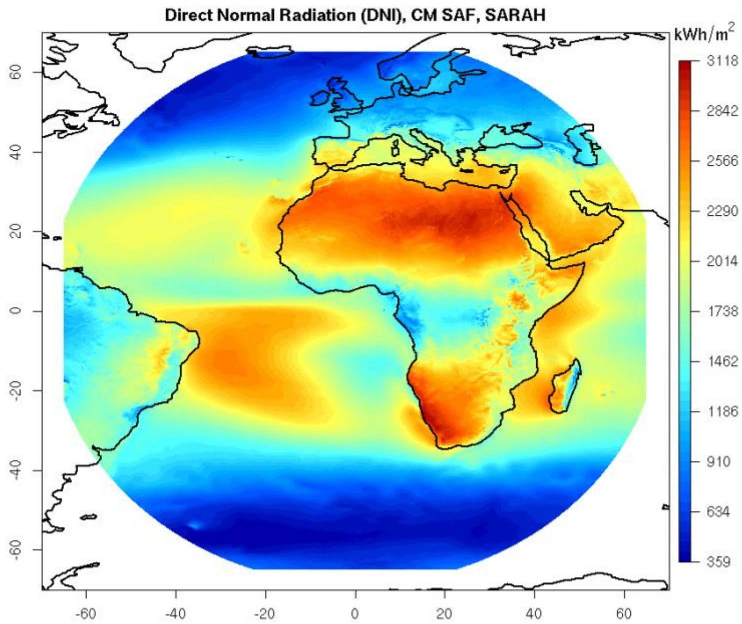

Figure B Temporally averaged direct normal irradiance (kWh/m^2/year) for Africa for the period 1983-2013.

Ground slope

CSP plants such as solar tower plants are limited by ground inclination and should be built on relatively flat land to minimize the cost of land flattering. We use the digital elevation model (DEM) obtained from the NASA Shuttle Radar Topography Mission (SRTM) (Jarvis *et al.*, 2008) at a resolution of 300 x 300 m to calculate slope values in terms of percentage.

Land cover

We use land cover data from the Land Cover (2008-2012) project of the Climate Change Initiative (CCI) led by the European Space Agency (ESA) at a resolution of 300 x 300 m (ESA Climate Change Initiative, 2014). This dataset includes information regarding forest coverage, woodlands, shrub lands and grasslands, agriculture, bare soil and salt hardpans, water bodies, and settlements, among other land cover typologies. Information regarding shifting sands is from the Global Land Cover 2000 by the European Joint Research Centre (Mayaux *et al.*, 2003) at a resolution of 1 x 1 km.

Land cover: Shifting sands

Dunes may incur high costs for earth removal and the creation of a suitably stable foundation for both solar plant construction and erection of transmission pylons (Trieb *et al.*, 2009a). Shifting dunes may, although they move slowly, bury an installation in its path, so that areas within the trajectories of existing shifting dunes must be excluded (Trieb *et al.*, 2009a).

Concerning shifting sands, the available data–from the geographic information layer *sandy desert and dunes* of the Global Land Cover 2000 dataset or from literature such as (Ashkenazy *et al.*, 2012; Sharaky *et al.*, 2002)–is not of sufficiently high spatial resolution or sufficiently strong classification certainty to clearly identify shifting sands in the Sahara Desert. Given the lack of reliable data, our exclusion mask may have a slight error concerning shifting sands and should be treated with caution. In some areas of the Sahara, dune mobility in some particular areas of the desert may achieve up to 100 m/year and is mainly directed to the south (Embabi, 1982). However, in the Namib Desert dune mobility is only some 0.1 m/year (Bristow *et al.*, 2007), and in the Kalahari Desert dunes are stable dunes fixed by vegetation (Ashkenazy *et al.*, 2012; Sharaky *et al.*, 2002). Considering an average CSP life plant of 30 years (Turchi and Heath, 2013), we have created a protecting buffer of 3 km around Sahara moving dunes to ensure the integrity of the facility during the operation lifetime. We do not consider dune mobility in the other deserts of Africa, as these dunes move too slowly.

Further, sandstorms are sometimes mentioned as a potential problem due to mirror abrasion. We do not consider sandstorms in our exclusion mask, both as they can–in principle–happen anywhere in sandy deserts and as there is no evidence of this being a serious problem for CSP stations (Patt *et al.*, 2013).

Land cover: Salt hardpans

Salt hardpans are dry, saline deserts, forming a highly corrosive environment unsuited for CSP or transmission installation (Trieb *et al.*, 2009a). The main hardpans are Etosha and Magadikgadi Pans in Southern Africa, the Natron Lake in East Africa, and the Chotts in Northern Africa. We exclude all salt hardpans from consideration in this analysis.

Land cover: Water bodies

All water bodies are unsuitable for CSP plants and we exclude them in this study. However, we classify narrow water bodies (i.e. rivers) as complicated, and hence more expensive, but possible for the installation of transmission infrastructure, thus allowing transmission lines to cross rivers.

Land cover: Settlements and commercial industrial areas

We exclude all areas currently used for settlements. We also exclude a 3 km buffer zone around airports (OurAirports, 2011) to avoid the collisions of airplanes with power lines or solar towers.

Protected areas

The World Database on Protected Areas (WDPA) is the most extensive dataset on protected areas worldwide, which is why we use it here (UNEP-WCMC and IUCN, 2010a). The WDPA is a collaborative project between the United Nations Environment Programme-World Conservation Monitoring Centre (UNEP-WCMC) and the International Union for Nature Conservation (IUCN) World Commission on Protected Areas (WCPA). In this, a protected area is defined as "a clearly defined geographical space, recognized, dedicated and managed through legal or other effective means, to achieve the long term conservation of nature with associated ecosystem services and cultural values" (Dudley, 2009). We exclude all protected areas described in WDPA, see Table C, as well as a 2 km buffer around them to provide a safety region for nature conservation.

Table C Categories of protected areas unsuitable for CSP plant location.

Categories	
I	Strict protection [a) Strict nature reserve and b) Wildness area]
II	Ecosystem conservation and protection (i.e., National Park)
III	Conservation of natural features (i.e. Natural Monuments)
IV	Conservation through active management (i.e. Habitat/Species management area)
V	Landscape/seascape conservation and recreation (i.e. Protected landscape/Seascape)
VI	Sustainable use of natural resources (i.e. Managed resource protected areas)

Availability of land

A utility-scale CSP plant requires substantial amounts of land: typically, a solar tower plant at a good site (2,600 kWh/m^2/year) requires up to some 17,000 m^2/MW for the land directly occupied by solar arrays, access roads, substations, and other infrastructure. When including all the land enclosed within the site boundary, land requirements increase up to some 40,500 m^2/MW (Ong *et al.*, 2013). Land, however, is often abundant and available at relatively low cost in the areas where CSP is suitable, such as deserts. After applying the exclusion criteria, the remaining land with a continuous area of less than 2 km^2 is also excluded for CSP plant location, as this would be too small to accommodate the 100 MW solar tower plants we assume here (see Table D).

B4 Calculation of electricity cost at the point of demand

The third set of tools refers to the calculation of the solar electricity cost at the point of demand. The levelized electricity cost (LEC) is a useful metric when analyzing investment opportunities for renewable energy technologies. As defined by the Energy Information Administration (EIA), "levelized cost represents the present value of the total cost of building and operating a generating plant over an assumed financial life and duty cycle, converted to equal annual payments and expressed in terms of real dollars to remove the impact of inflation" (EIA, 2011). A LEC approach allows for a like-for-like comparison of the generation costs of different technologies for the expected life of the facilities, as well as it provides a measure of a renewable technology's competitiveness and is valuable in determining the need for publicly funded financial incentives. A levelized cost approach does not, however, factor in the cost of intermittency balancing and the different value of peak/off peak generation costs, or portfolio and merit-order effects of renewable energy technologies.

The LEC at the point of demand LECdem(i) is the sum of the levelized generation cost LECgen(i) and the levelized transmission cost LECtrans(i) (see Equation B1-Equation B3). We use the depreciation rate to calculate the annuity at which capital expenditures (i.e. investments for power plant and transmission line components) are included in the system cost (see Equation A10). To reflect varying political and legal risks for investors we apply country-specific WACCs in the calculation of country-specific LECgen and LECtrans (see Table 1 for country-specific WACCs). Table D shows the technical and economic parameters used to calculate LECdem(i). We express all costs in US$$_{2012}$. Costs for the solar tower plant were already in US$$_{2012}$. Costs for the transmission projects and costs of typical fossil fuel power generation in Africa used as benchmark were in US$$_{2011}$ and US$$_{2010}$, respectively, and adjusted to US$$_{2012}$ using the US GDP deflator from the Bureau of Economic Analysis U.S. Department of Commerce.

$$\boldsymbol{LEC_{dem}}(\mathbf{i}) = \boldsymbol{LEC_{gen}}(\mathbf{i}) + \boldsymbol{LEC_{trans}}(\boldsymbol{i}) \tag{B1}$$

$$\boldsymbol{LEC_{gen}}(\mathbf{i}) = \frac{\boldsymbol{C_{cons}}(\boldsymbol{i}) \times \boldsymbol{dep}(\boldsymbol{i}) + \boldsymbol{C_{om\,gen}}(\boldsymbol{i})}{\boldsymbol{E_{gen}}(\boldsymbol{i})} \tag{B2}$$

$$\boldsymbol{LEC_{trans}}(\mathbf{i}) = \frac{\boldsymbol{C_{trans}}(\boldsymbol{i}) \times \boldsymbol{dep}(\boldsymbol{i}) + \boldsymbol{C_{om\,trans}}(\boldsymbol{i})}{\boldsymbol{E_{trans}}(\boldsymbol{i})} \tag{B3}$$

The levelized generation cost $LEC_{gen}(i)$ for each plant is given by the construction cost $C_{cons}(i)$ and the operations and maintenance cost $C_{om\ gen}(i)$.

$$C_{cons}(i) = (P_{gen} \times h_{stor} \times C_{stor}) + \left(\frac{P_{gen} \times 8760 \times CF}{DNI \times \eta} \times C_{sf}\right) + (P_{gen} \times C_{pb}) + (P_{gen} \times C_{sg}) + (P_{gen} \times C_{rec}) \quad \text{(B4)}$$

$$C_{om\ gen}(\mathbf{i}) = (P_{gen} \times C_{om}) + (E_{gen} \times C_{om\ var}) \quad \text{(B5)}$$

$$E_{gen}(i) = P_{gen} \times 8760 \times CF \quad \text{(B6)}$$

The levelized transmission cost $LEC_{trans}(i)$ for each transmission line is given by the construction cost $C_{trans}(i)$ and the operations and maintenance cost $C_{om\ trans}(i)$.

$$C_{trans}(i) = (T_{dist} \times C_{trans} \times P_{trans}) + (C_{con} \times P_{trans} \times 2) \quad \text{(B7)}$$

$$C_{om\ trans}(\mathbf{i}) = (T_{dist} \times C_{trans} \times P_{trans} \times T_{om\ line}) + (C_{con} \times P_{trans} \times T_{om\ con} \times 2) \quad \text{(B8)}$$

$$E_{trans}(i) = (P_{trans} \times 8760) - ((T_{loss\ line} \times T_{dist} \times P_{trans} \times 8760) + (T_{loss\ con} \times P_{trans} \times 8760 \times 2)) \quad \text{(B9)}$$

The depreciation rate is given by

$$dep(\mathbf{i}) = \frac{r_n \times (1 + r_n)^{T}}{(1 + r_n)^{T} - 1} \quad \text{(B10)}$$

Table D Technical and economic parameters describing the solar plant and transmission system.

Variable	Description	Value	Unit	Source
DNI	Annual direct normal irradiance	≥ 2,000	kWh/m^2/year	See B3 Data
P_{gen}	Plant capacity	100,000	kW_e	See Table E
h_{stor}	Storage time	10	hours	See Table E
T	Plant life time	30	years	Assumption
C_{stor}	Thermal storage cost	27	\$/kWh_t	See Table E
C_{sf}	Solar field cost	180	\$/m^2	See Table E
C_{pb}	Power block cost	1,200	\$/kW_e	See Table E
C_{sg}	Steam generation cost	350	\$/kW_e	See Table E
C_{rec}	Receiver cost	173	\$/kW_t	See Table E
C_{om}	O&M costs plant	65	\$/kW/year	See Table E
$C_{om\ var}$	Variable O&M costs plant	0.004	\$/kWh	See Table E
η	Annual solar-to-electric efficiency	14.8	%	See Table E
CF	Annual capacity factor	See Equation B11	-	See Table E
SM	Solar Multiple	2.4	-	See Table E
r	Country-specific WACC	Variable	%	See Table 1
T_{dist}	Transmission distance	Variable	Km	-

	Voltage level (HVDC and HVAC)	± 600 and ± 500	kV	See Table E
P_{trans}	Transmission capacity	2,000,000	kW	See Table E
T	Transmission infrastructure life time	40	years	Assumption
C_{trans}	Transmission cost (HVDC and HVAC)	0.151 and 0.286	$/kW/km	See Table E
C_{con}	Converter cost for HVDC (x2)	130	$/kW	See Table E
$T_{loss\ line}$	Transmission losses (HVDC and HVAC)	4.5 and 6.8	%/1,000 km	See Table E
$T_{loss\ con}$	Converter station losses (x2)	0.7	%	See Table E
$T_{om\ line}$	O&M costs line (HVDC and HVAC)	2	%	See Table E
$T_{om\ con}$	O&M costs converter	1	%	See Table E
r	Country-specific WACC	Variable	%	See Table 1

As we use a levelized cost approach, the size of the power plant does not matter. In reality, larger power stations generally have lower levelized costs due to economies of scale, leading to lower specific investment costs. We use data for a 100 MW CSP station with 10 hours of storage, and although the effect of varying the size of the station to achieve a net output capacity equal than the capacity of the transmission line would be limited, our cost calculations refer to this configuration only.

The equation to estimate the capacity factor of the CSP plant was derived by Trieb *et al.* (2012) from hourly time series of the performance of parabolic trough plants. The same equation can be used to describe the capacity factor of solar tower plants.

$$CF = (2.5717 \times DNI + 694) \times (-0.0371 \times SM^2 + 0.4171 \times SM - 0.0744) \qquad \text{(B11)}$$

Transmission costs were derived from the regional power system master plan for the Eastern Africa Power Pool and the East African Community (SNC-Lavalin and Brinckerhoff, 2011). Costs of the HVDC and HVAC transmission lines and converter stations are from projects planned by the regional power system master plan for a transmission line Egypt-Sudan 600kV-HVDC bi-pole and 2,000MW, and a Ethiopia-Sudan line 500kV-AC double-circuit and 1,600MW, to start operation in 2025.

Table E Data types and sources used in the model.

Type	Source(s)	Comments
Solar tower plant	Turchi and Heath (2013)	Plant capacity, storage capacity, thermal storage, mirror field, power block, steam generation system, receiver, O&M costs, efficiency
	(Trieb *et al.*, 2012)	Capacity factor
Transmission	(SNC-Lavalin and Brinckerhoff, 2011)	Transmission line costs and converter station costs
	(Trieb *et al.*, 2012)	Transmission line losses and converter station losses

B5 Results

Base case

Table F Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under base case assumptions, with 2012 technology costs and projected 2025 costs. Electricity trade is limited to the power pools; financing costs are country-specific, technology costs have a cost penalty, fragile countries are excluded from being a generation, transit or importing country. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Figure 1 in the main article.

	Base case 2012	Base case 2025
	cents per kWh	**cents per kWh**
Western Power Pool	**2,900 kWh/m²**	**2,900 kWh/m²**
Accra, Ghana	20.0*	14.1*
Bamako, Mali	19.7*	13.8*
Dakar, Senegal	20.1*	14.2*
Lagos, Nigeria	19.4*	13.5*
Niamey, Niger	19.2*	13.3*
Ouagadougou, Burkina Faso	19.4*	13.5*
Porto Novo, Benin	19.4*	13.5*
Southern Power Pool	**2,900 kWh/m²**	**2,900 kWh/m²**
Dar es Salaam, Tanzania	12.9*	9.8*
Gaborone, Botswana	10.4*	7.3*
Johannesburg, RSA	10.4*	7.3*
Luanda, Angola	11.0*	7.8*
Lusaka, Zambia	11.0*	7.8*
Maputo, Mozambique	10.9*	7.7*
Windhoek, Namibia	9.9	6.7
Central Power Pool	**2,300 kWh/m²**	**2,300 kWh/m²**
Brazzaville, RC	22.0*	15.2*
Douala, Cameroon	21.7*	14.9*
Libreville, Gabon	21.9*	15.0*
Eastern Power Pool	**2,600 kWh/m²**	**2,600 kWh/m²**
Addis Ababa, Ethiopia	19.8	13.4
Kampala, Uganda	19.6	13.2
Nairobi, Kenya	19.4	13.1

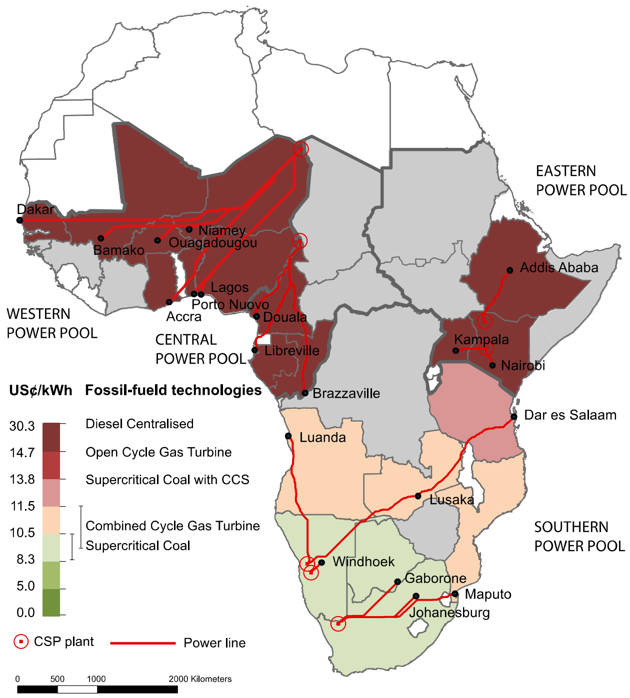

Figure C Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and locations of associated generation sites and transmission lines under base case assumptions; using 2012 technology costs. Countries in grey are fragile states.

Scenario variations: Scenarios a, b, c, and d

Table G Levelized electricity cost (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under the assumptions from the different scenarios, with 2012 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Figure 1 in the main article.

	Scenario a	Scenario b	Scenario c	Scenario d
	Unrestricted trade	WACC 5%	Investment least-cost countries	With variations a, b and c
	cents per kWh	cents per kWh	cents per kWh	cents per kWh
Western Power Pool	**2,900 kWh/m²**	**2,900 kWh/m²**	**2,900 kWh/m²**	**2,900 kWh/m²**
Accra, Ghana	19.0*	8.7*	16.3*	7.1*
Bamako, Mali	19.7*	8.8*	16.0*	7.1*
Dakar, Senegal	20.1*	8.9*	16.4*	7.3*
Lagos, Nigeria	18.4*	8.7*	15.7*	7.0*
Niamey, Niger	19.2*	8.6*	15.5*	7.0*
Ouagadougou, Burkina Faso	19.4*	8.6*	15.7*	7.0*
Porto Novo, Benin	18.4*	8.7*	15.7*	7.1*
Southern Power Pool	**2,900 kWh/m²**	**2,900 kWh/m²**	**2,900 kWh/m²**	**2,900 kWh/m²**
Dar es Salaam, Tanzania	12.9*	7.6*	12.4*	7.2*
Gaborone, Botswana	10.4*	7.2*	9.8*	6.8*
Johannesburg, RSA	10.4*	7.2*	9.9*	6.8*
Luanda, Angola	11.0*	7.3*	10.4*	6.9*
Lusaka, Zambia	11.0*	7.3*	10.4*	6.9*
Maputo, Mozambique	10.9*	7.3*	10.3*	6.9*
Windhoek, Namibia	9.9	6.9	9.3	6.5
Central Power Pool	**2,900 kWh/m²**	**2,300 kWh/m²**	**2,300 kWh/m²**	**2,900 kWh/m²**
Brazzaville, RC	13.9*	10.5*	17.7*	7.0*
Douala, Cameroon	18.3*	10.4*	17.4*	7.0*
Libreville, Gabon	13.1*	10.4*	17.6*	7.1*
Eastern Power Pool	**2,900 kWh/m²**	**2,600 kWh/m²**	**2,600 kWh/m²**	**2,900 kWh/m²**
Addis Ababa, Ethiopia	18.9*	9.1	15.8	7.0*
Kampala, Uganda	18.7*	9.0	15.6	7.1*
Nairobi, Kenya	18.9*	9.0	15.5	7.2*

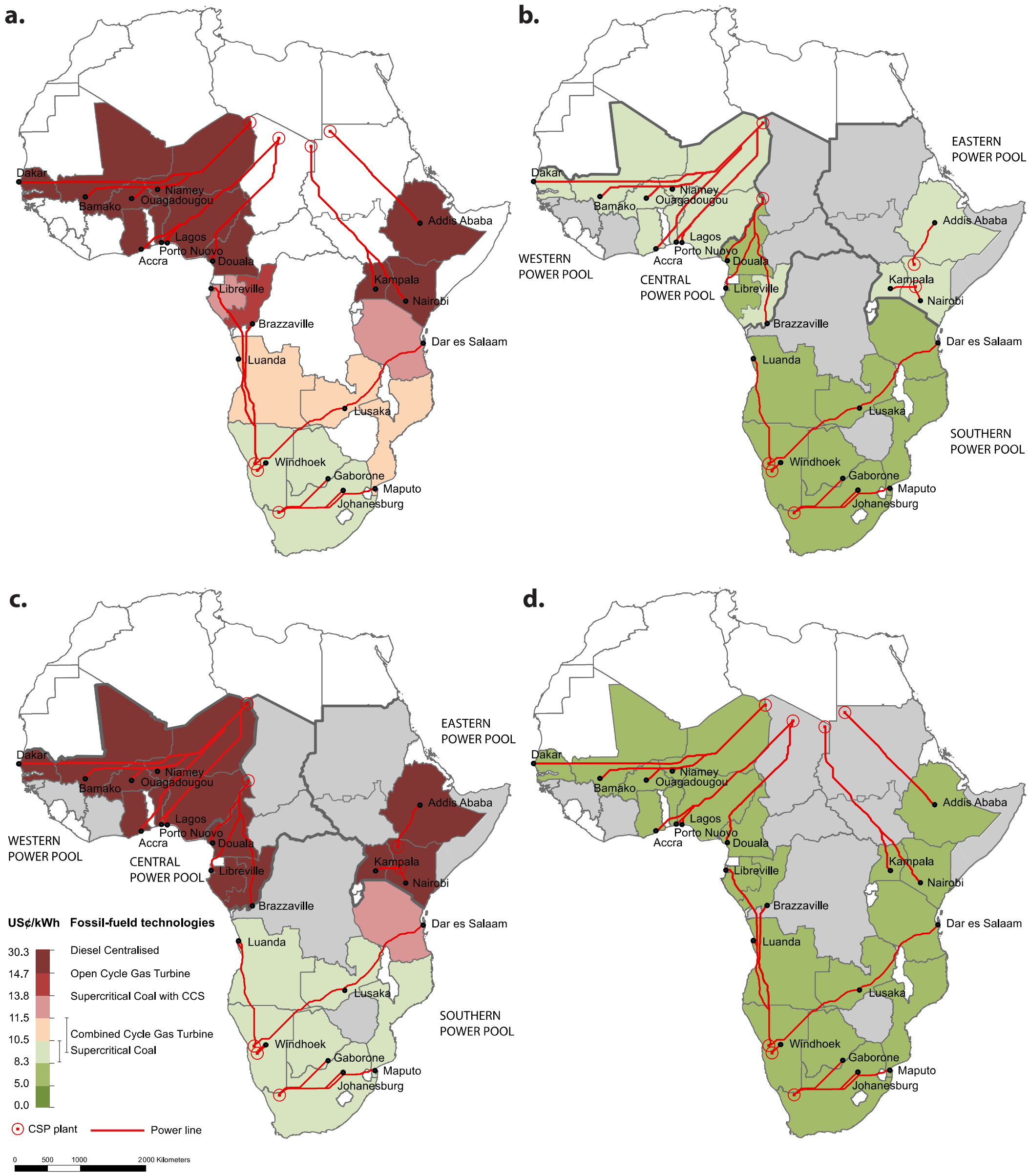

Figure D Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, and location of associated transmission lines using 2012 technology costs; (a) under unrestricted trade; (b) WACC 5%; (c) investment cost from industrialized countries; (d) considers all assumptions from previous scenarios. Countries in grey are fragile states.

Table H Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries under the assumptions from the different scenarios, with projected 2025 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Figure 1 in the main article.

	Scenario a	Scenario b	Scenario c	Scenario d
	Unrestricted trade	WACC 5%	Investment industrialized countries	With variations a, b and c
	cents per kWh	cents per kWh	cents per kWh	cents per kWh
Western Power Pool	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**
Accra, Ghana	13.5*	6.1*	11.6*	5.1*
Bamako, Mali	13.8*	6.2*	11.3*	5.1*
Dakar, Senegal	14.2*	6.4*	11.8*	5.3*
Lagos, Nigeria	12.8*	6.1*	11.0*	5.0*
Niamey, Niger	13.3*	6.0*	10.8*	4.9*
Ouagadougou, Burkina Faso	13.5*	6.1*	11.0*	5.0*
Porto Novo, Benin	12.8*	6.1*	11.0*	5.0*
Southern Power Pool	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**
Dar es Salaam, Tanzania	9.8*	5.5*	9.4*	5.2*
Gaborone, Botswana	7.3*	5.0*	6.9*	4.8*
Johannesburg, RSA	7.3*	5.1*	6.9*	4.8*
Luanda, Angola	7.8*	5.2*	7.4*	4.9*
Lusaka, Zambia	7.8*	5.2*	7.4*	4.9*
Maputo, Mozambique	7.7*	5.1*	7.4*	4.9*
Windhoek, Namibia	6.7	4.7	6.4	4.5
Central Power Pool	**2,900 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,900 kWh/m^2**
Brazzaville, RC	10.1*	7.3*	12.3*	5.0*
Douala, Cameroon	12.7*	7.1*	12.0*	5.0*
Libreville, Gabon	9.3*	7.2*	12.2*	5.1*
Eastern Power Pool	**2,900 kWh/m^2**	**2,600 kWh/m^2**	**2,600 kWh/m^2**	**2,900 kWh/m^2**
Addis Ababa, Ethiopia	13.1*	6.3	10.8	4.9*
Kampala, Uganda	13.2*	6.2	10.6	5.0*
Nairobi, Kenya	13.4*	6.1	10.5	5.1*

Scenario variation: Scenario e

Table I Levelized electricity costs (cents per kWh) for the power supplied by CSP to demand centers in sub-Saharan countries, from sites with the highest domestic irradiance. Base case is under base case assumptions; scenarios *b*, *c*, and *d* are under the assumptions from the different scenarios, all with projected 2025 technology costs. An asterisk (*) represents projects with HVDC transmission, the remaining represent projects with HVAC. The color code is the same as in Figure 1 in the main article. *np* means not possible.

	Base case	**Scenario b**	**Scenario c**	**Scenario d**
		WACC 5%	**Investment industrialized countries**	**With variations b and c**
	cents per kWh	**cents per kWh**	**cents per kWh**	**cents per kWh**
Western Power Pool	**2,000 kWh/m^2**	**2,000 kWh/m^2**	**2,000 kWh/m^2**	**2,000 kWh/m^2**
Accra, Ghana	23.1	7.8	18.4	6.3
	2,600 kWh/m^2	**2,600 kWh/m^2**	**2,600 kWh/m^2**	**2,600 kWh/m^2**
Bamako, Mali	14.4*	6.5*	11.7*	5.3*
	2,300 kWh/m^2	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**
Dakar, Senegal	14.7	6.8	11.8	5.5
	2,300 kWh/m^2	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**
Lagos, Nigeria	15.1*	7.1*	12.2*	5.8*
	2,900 kWh/m^2	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**
Niamey, Niger	13.3*	6.0*	10.8*	4.9*
	2,300 kWh/m^2	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**
Ouagadougou, Burkina Faso	15.4	6.8	12.3	5.5
	2,100 kWh/m^2	**2,100 kWh/m^2**	**2,100 kWh/m^2**	**2,100 kWh/m^2**
Porto Novo, Benin	16.3	7.5	13.0	6.1
Southern Power Pool	**2,600 kWh/m^2**	**2,600 kWh/m^2**	**2,600 kWh/m^2**	**2,600 kWh/m^2**
Dar es Salaam, Tanzania	11.2	5.3	10.6	5.0
	2,700 kWh/m^2	**2,700 kWh/m^2**	**2,700 kWh/m^2**	**2,700 kWh/m^2**
Gaborone, Botswana	7.7	5.2	7.2	4.9
	2,900 kWh/m^2	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**
Johannesburg, RSA	7.3*	5.1*	6.9*	4.8*
	2,700 kWh/m^2	**2,700 kWh/m^2**	**2,700 kWh/m^2**	**2,700 kWh/m^2**
Luanda, Angola	11.6*	5.4*	11.0*	5.1*
	2,400 kWh/m^2	**2,400 kWh/m^2**	**2,400 kWh/m^2**	**2,400 kWh/m^2**
Lusaka, Zambia	11.0	5.6	10.4	5.3
	2,400 kWh/m^2	**2,400 kWh/m^2**	**2,400 kWh/m^2**	**2,400 kWh/m^2**
Maputo, Mozambique	12.7*	6.0*	12.0*	5.6*
	2,900 kWh/m^2	**2,900 kWh/m^2**	**2,900 kWh/m^2**	**2,900 kWh/m^2**
Windhoek, Namibia	6.7	4.7	6.4	4.5
Central Power Pool	**< 2,000 kWh/m^2**	**< 2,000 kWh/m^2**	**< 2,000 kWh/m^2**	**< 2,000 kWh/m^2**
Brazzaville, RC	np	np	np	np
	2,300 kWh/m^2	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**

Douala, Cameroon	14.9*	7.2*	12.0*	5.8*
	< 2,000 kWh/m^2	**< 2,000 kWh/m^2**	**< 2,000 kWh/m^2**	**< 2,000 kWh/m^2**
Libreville, Gabon	np	np	np	np
Eastern Power Pool	**2,500 kWh/m^2**	**2,500 kWh/m^2**	**2,500 kWh/m^2**	**2,500 kWh/m^2**
Addis Ababa, Ethiopia	9.4	6.4	7.6	5.1
	2,300 kWh/m^2	**2,300 kWh/m^2**	**2,300 kWh/m^2**	**2,300 kWh/m^2**
Kampala, Uganda	17.9	6.8	14.3	5.5
	2,600 kWh/m^2	**2,600 kWh/m^2**	**2,600 kWh/m^2**	**2,600 kWh/m^2**
Nairobi, Kenya	13.1	6.1	10.5	4.9