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Bundesamt für Energie BFE
Sektion Energieversorgung und Monitoring

Potenziale, Kosten und Umweltauswirkungen von Stromproduktionsanlagen

Aufdatierung des Hauptberichts (2017), mit Zusammenfassung auf Deutsch, Französisch und Italienisch

Datum: September 2019

Ort: Bern

Auftraggeberin: Bundesamt für Energie BFE, 3003 Bern

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Potentials, costs and environmental assessment of electricity generation technologies

An update of electricity generation costs and potentials

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September 16, 2019

PSI, Technology Assessment group

SCCER supply of electricity

www.psi.ch/ta

http://www.sccer-soe.ch

This report has been prepared by PSI on behalf of the Swiss Federal Office of Energy (SFOE).

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1 Summary

The Swiss Federal Office of Energy (SFOE) regularly surveys the potential, costs and environmental impacts of electricity production technologies, for the last time in 2017 (Bauer et al. 2017). In the meantime, the production costs for photovoltaic (PV) modules have fallen further. In addition, there is a new basis for the estimation of potential of PV systems in Switzerland[1] and the potential of hydropower has also been updated since then. Against this background, the SFOE has commissioned PSI to update the production costs of those technologies for which significant changes can be assumed since 2017. These are mainly photovoltaics and European offshore wind power plants. The electricity production costs of fossil-thermal power plants (CCGT, CHP and fuel cells) were also adjusted on the basis of current price data for natural gas. As in the previous study, the current electricity production costs ("levelized costs of electricity", LCOE; reference year: 2018) are shown first; on this basis, an estimate of the development of the costs up to the year 2050 is made. For other technologies not included in this report (Chapter 10), it is assumed that the costs from the previous study are still valid. The LCOE of these technologies are shown in the comparative graphs[2] to provide a complete overview – details can be found in the previous study (Bauer et al. 2017). All figures[3] are also part of the data sheets of the individual technologies (Chapter 3).

As a supplement to updating the electricity production costs, cost potential curves were established in the present study for photovoltaic roof systems, which show how much electricity can be produced with these systems and at what cost. For this purpose, the new cost data were combined with the newly available information on available roof areas from the platform "sonnendach.ch". These cost-potential curves represent technical potentials for electricity production with photovoltaic systems on existing roofs in Switzerland, in each case at certain production costs. According to the available roof area data[4], the technical potential for electricity production from solar energy in Switzerland is up to 63 TWh per year (excluding facades). The economic potential will increase sharply in the future thanks to falling costs: If the "economic limit" is set at 15 Rp/kWh, then with current investment costs and specific space requirements of the PV modules, there is a technical-economic potential on roofs of around 10 TWh/a; this will increase in the future thanks to decreasing costs and less space requirements and is put at a good 50 TWh/a for 2035. With a lower "economic limit" of 11 Rp/kWh, there is a technical-economic potential of around 21 TWh in 2035. An annual production of 30 TWh could be realized at costs of at most approx. 13 Rp/kWh.[5] How much of this can actually be generated depends on the respective framework conditions.

The latest figures from SFOE on the expansion of hydropower have also been included (SFOE 2019): the total expansion potential of hydropower (large and small hydropower) by 2050 is now 540 - 2'160 GWh/a. In the 2017 study, an additional potential of 1'530 - 3'160 GWh/a was estimated, whereby the production volume expected today is already 640 GWh/a higher than in 2012 (SFOE 2012). The most important difference compared with 2012 is that the potential for small hydropower has been reduced by around 1000 GWh/a due to the phasing out of subsidies. Based on the average net production as of 1 January 2019 of 35'990 GWh/a, this results in an expected production of 36'530 - 38'150 GWh/a for the year 2050. As climate change progresses, the glaciers will shrink, creating glacial lakes that could also be used for hydropower. The SFOE estimates this additional potential to be around 700 GWh/a.

Figure 1.1 shows an overview of LCOE of current electricity generation technologies, based on the updates documented in sections 9 to 11 in this report (wind power, photovoltaics, natural gas fueled

[1] www.sonnendach.ch
[2] A mix of technologies will be required for a substantial expansion of renewable power generation.
[3] Updated figures in red.
[4] Source: https://www.uvek-gis.admin.ch/BFE/sonnendach/
[5] PV generation costs and potentials in this summary all refer to a "roof-top are utilization factor" of 70%.

combined cycle plants, CHP and fuel cells) and previously estimated costs according to (Bauer et al. 2017). Figure 1.2 shows cost estimates for year 2050.

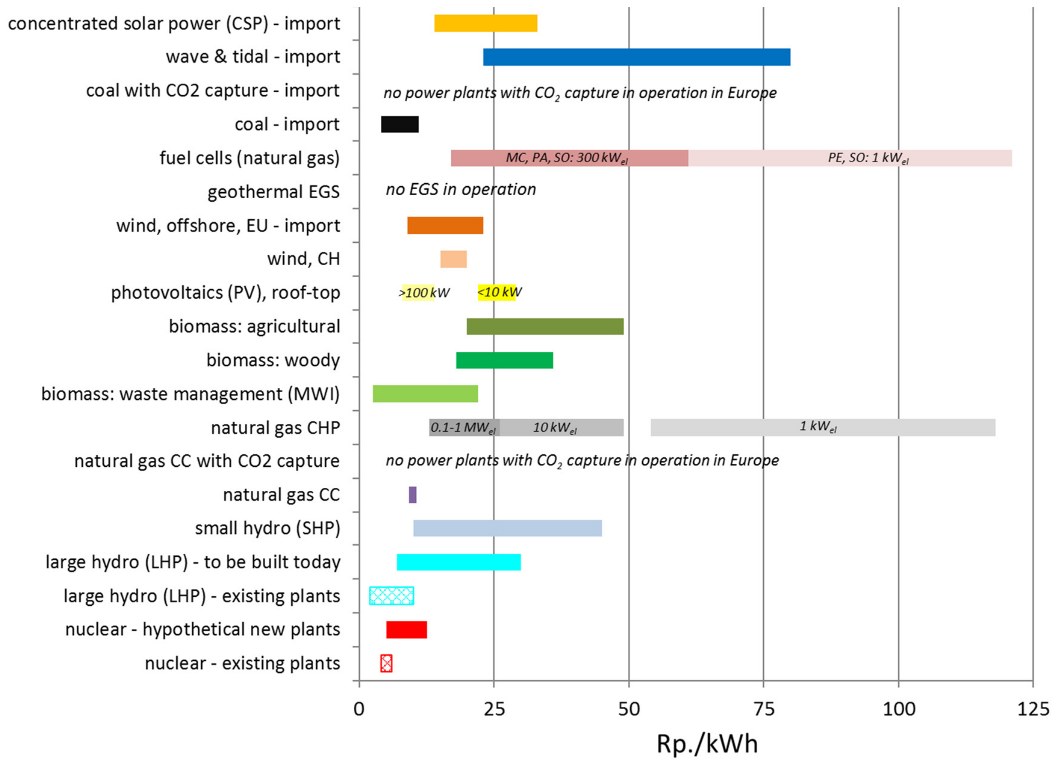

Figure 1.1: Current (year 2018) levelized costs of electricity (LCOE).[6] Ranges reflect variability in terms of site-conditions, technology characterization and biomass feedstock costs. Ranges for fuel cells, PV and NG CHP are mainly due to system capacities; LCOE for specific capacities are provided in the technology fact sheets (chapter 3) and the individual technology chapters. Electricity import costs with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Heat credits for natural gas and biomass CHP as well as fuel cells are considered. NG: natural gas; CC: combined cycle; CHP: combined heat and power; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; MC: molten carbonate; SO: solid oxide; PE: polymer electrolyte; PA: phosphoric acid; MWI: municipal waste incineration; "coal" includes hard coal and lignite.

The changes in the current electricity production costs compared to the previous study are visible, but not substantial: The current electricity production costs of wind power plants in Switzerland remain roughly the same, while the costs of electricity from offshore turbines in Europe (for electricity imports) decrease quite significantly compared to the previous estimate. The updated costs of electricity from PV roof systems in Switzerland are somewhat lower than two years ago. The electricity production costs of natural gas power plants, CHP plants and fuel cells are also somewhat lower, as the updated natural gas prices are slightly lower than previously assumed and technical advances in fuel cells are also reflected in the electricity production costs. In terms of expected electricity production costs in 2050, offshore wind turbines show the most significant reductions compared to the previous estimate, as the latest available literature sources are much more optimistic in their cost estimates. For other technologies, expected electricity production costs in 2050 have been slightly revised downwards or remain at the same level as in the previous estimate.

[6] For large hydropower and nuclear power, current costs of operating power plants, which include partially amortized capital costs, are also shown for comparison, since these power plants will be part of the Swiss generation mix for many more years. In case of nuclear power, "hypothetical new plants" correspond to hypothetical reactors of latest technology (Gen III), for which the planning process would start today. More details can be found in (Bauer et al. 2017).

With regard to data quality and robustness of results, a clear improvement can be noted compared to the previous study, especially in the case of photovoltaic systems. This applies on the one hand to the total investment costs – the sample of plants for which investment costs were available was small in 2016, while several hundred cost data points from the SwissEnergy Solar Offer Check[7] were now available. On the other hand, in the previous study the allocation of costs to modules, installation, etc. of large systems was transferred to all output classes, while specific figures are now also available for small systems. This makes the new calculations much more reliable and meaningful.

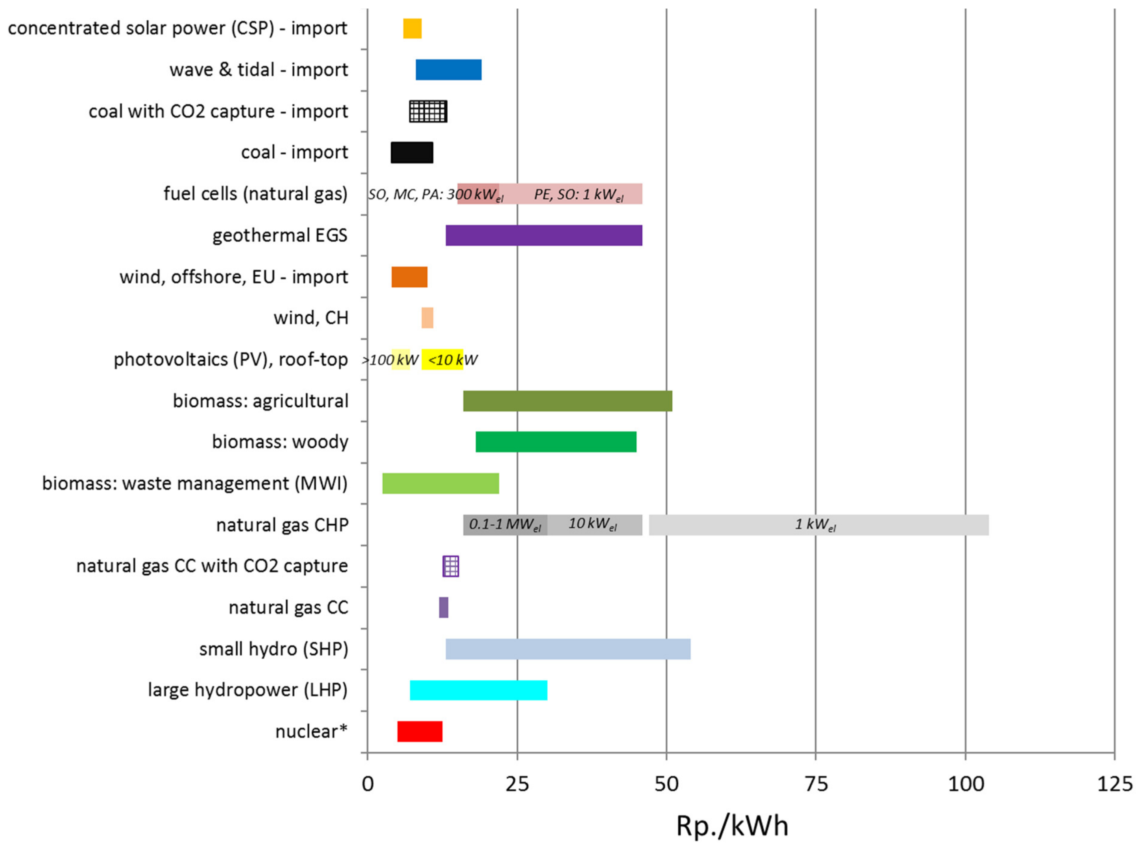

Figure 1.2: LCOE estimated for year 2050. Ranges reflect variability in terms of site-conditions, technology characterization, biomass feedstock costs and future technology cost developments. Ranges for fuel cells, PV and NG CHP are mainly due to system capacities; LCOE for specific capacities are provided in the technology fact sheets (chapter 3) and the individual technology chapters. Electricity import costs with dedicated HVDC lines are in the order of 0.5-2 Rp./kWh and would have to be accounted for in addition. Potential heat credits for EGS are not included.[8] Heat credits for natural gas and biomass CHP as well as fuel cells are considered. LCOE: Levelized costs of electricity; NG: natural gas; CC: combined cycle; CHP: combined heat and power; MWI: municipal waste incineration; LHP: large hydropower; SHP: small hydropower; CSP: concentrated solar power; PV: photovoltaics; EGS: enhanced geothermal systems; MC: molten carbonate; SO: solid oxide; PE: polymer electrolyte; PA: phosphoric acid; "coal" includes hard coal and lignite. *The LCOE range for nuclear represent Generation 3+ and small modular reactor (SMR) designs, since reliable cost estimates for Generation 4 designs, which might be an option in 2050, are not available.

[7] https://www.energieschweiz.ch/page/de-ch/solar-offerte-check

[8] The impact of heat credits on the economic viability of EGS will be substantial, since the electric efficiencies of EGS are comparatively low and large amounts of heat are generated. However, from the current perspective and due to risk-related social issues, it seems to be difficult to implement EGS at sites with large heat demand, i.e. in areas with large residential heat demand and district heat networks. Details can be found in (Bauer et al. 2017).

2 Zusammenfassung

Das Bundesamt für Energie (BFE) lässt regelmässig Potenziale, Kosten und Umweltauswirkungen von Stromproduktionstechnologien erheben, letztmals im Jahr 2017 (Bauer et al. 2017). In der Zwischenzeit sind die Gestehungskosten für Fotovoltaikmodule (PV) weiter gefallen. Zudem liegen neue Grundlagen zu den Potenzialen von PV-Dachanlagen in der Schweiz vor[9] und auch die Potenziale der Wasserkraft wurden seither aufdatiert. Vor diesem Hintergrund hat das BFE das PSI beauftragt, eine Aktualisierung der Gestehungskosten jener Technologien vorzunehmen, für welche seit 2017 wesentliche Veränderungen vermutet wurden. Es handelt sich dabei im Wesentlichen um die Fotovoltaik sowie um europäische Offshore-Windkraftanlagen. Auch die Stromproduktionskosten von fossil-thermischen Kraftwerken (GuD, WKK und Brennstoffzellen) wurden anhand aktueller Preisdaten für Erdgas angepasst. Wie schon in der vorangegangenen Studie werden zunächst die heutigen Stromproduktionskosten («levelized costs of electricity», LCOE; Referenzjahr: 2018) ausgewiesen; aufbauend darauf wird eine Abschätzung der Entwicklung der Kosten bis ins Jahr 2050 vorgenommen. Für weitere Technologien, welche nicht Bestandteil dieses Berichts sind (Kapitel 12), wird angenommen, dass die Kosten aus der vorangehenden Studie immer noch gültig sind. Die LCOE dieser Technologien sind in den Vergleichsgrafiken dargestellt, um einen vollständigen Überblick[10] zu ermöglichen – Details dazu sind in der Vorgängerstudie zu finden (Bauer et al. 2017). Sämtliche Zahlen[11] sind zudem in den Datenblättern der einzelnen Technologien enthalten (Kapitel 3).

Als Ergänzung zur Aktualisierung der Stromproduktionskosten wurden in der vorliegenden Studie für Fotovoltaik-Dachanlagen Kosten-Potenzialkurven erstellt, welche zeigen, wie viel Strom mit diesen Anlagen zu welchen Kosten produziert werden kann. Dafür wurden die neuen Kostendaten mit den neu verfügbaren Informationen zu verfügbaren Dachflächen aus der Solarplattform «sonnendach.ch» kombiniert. Diese Kosten-Potenzialkurven repräsentieren technische Potenziale zur Stromproduktion mit Fotovoltaikanlagen auf vorhandenen Dächern in der Schweiz, dies jeweils zu bestimmten Produktionskosten. Den Daten bzgl. verfügbarer Dachfläche zufolge[12] beträgt das technische Potenzial zur Stromproduktion aus Sonnenenergie in der Schweiz bis zu 63 TWh pro Jahr (noch ohne Fassaden). Das wirtschaftliche Potenzial wird sich dank abnehmender Kosten in Zukunft stark erhöhen: Setzt man die «Wirtschaftlichkeitsgrenze» bei 15 Rp./kWh an, dann ergibt sich mit heutigen Investitionskosten und spezifischem Flächenbedarf der Anlagen ein technisch-wirtschaftliches Potenzial auf Dächern von rund 10 TWh/a; dies wird zukünftig dank abnehmender Kosten und weniger Flächenbedarf ansteigen und für 2035 mit gut 50 TWh/a beziffert. Bei einer tiefer angesetzten «Wirtschaftlichkeitsgrenze» von 11 Rp./kWh ergeben sich technisch-wirtschaftliche Potenziale von rund 21 TWh im Jahr 2035. Eine Jahresproduktion von 30 TWh könnte dann zu Kosten von höchstens ca. 13 Rp./kWh realisiert werden.[13] Wie viel davon tatsächlich erzeugt werden kann, hängt von den jeweiligen Rahmenbedingungen ab.

Auch die neusten Zahlen des BFE zum Zubau der Wasserkraft wurden berücksichtigt (SFOE 2019): Das gesamte Ausbaupotenzial der Wasserkraft (Gross- und Kleinwasserkraft) bis 2050 beträgt neu 540 bis 2'160 GWh/a. In der Studie 2017 wurde ein Zubaupotenzial von 1'530 - 3'160 GWh/a geschätzt (SFOE 2012), wobei die heute erwartete Produktionsmenge bereits 640 GWh/a höher liegt als noch 2012. Wichtigster Unterschied gegenüber 2012 ist, dass sich das Potenzial bei der Kleinwasserkraft wegen der auslaufenden Förderung um rund 1000 GWh/a reduziert hat. Ausgehend von der mittleren Nettoproduktion per 1.Januar 2019 von 35‘990 GWh/a ergibt dies eine erwartete Produktion für das Jahr 2050 von 36‘530 - 38‘150 GWh/a. Durch den fortschreitenden Klimawandel

[9] www.sonnendach.ch
[10] Ein Mix von Technologien wird entscheidend sein, um einen Ausbau der Erneuerbaren voranzutreiben.
[11] Aktualisierte Werte in Rot.
[12] Quelle: https://www.uvek-gis.admin.ch/BFE/sonnendach/
[13] Alle PV-bezogenen Zahlen hier sind mit einem «Dachausnutzungsfaktor» von 70% berechnet.

werden Gletscher schrumpfen – dabei werden Gletscherseen entstehen, welche auch für die Wasserkraft genutzt werden könnten. Dieses zusätzliche Potenzial wird auf rund 700 GWh/a geschätzt.

In Abbildung 2.1 sind heutige, technologiespezifische Stromproduktionskosten dargestellt, in Abbildung 2.2 jene für das Jahr 2050. Die hier enthaltenen Kosten basieren auf den in Kapiteln 9 bis 11 dokumentierten Aktualisierungen und auf den weiterhin gültigen Zahlen aus (Bauer et al. 2017) für die restlichen Technologien.

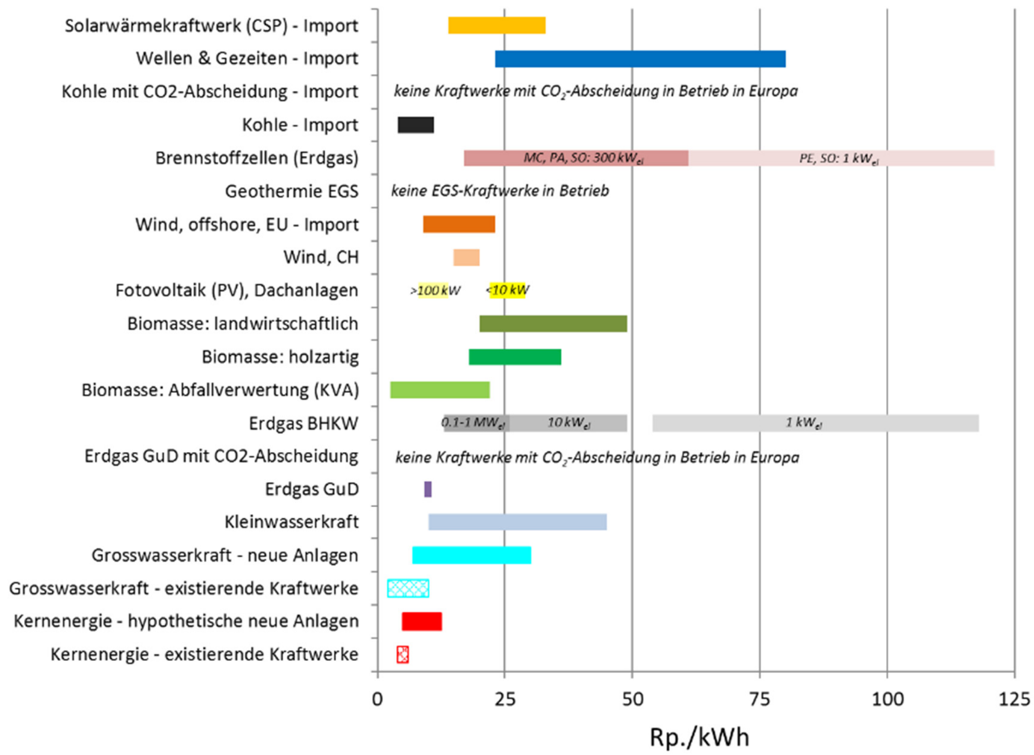

Abbildung 2.1: Heutige Stromproduktionskosten (Referenzjahr 2018).[14] Die dargestellten Bandbreiten spiegeln Variabilität aufgrund standortspezifischer Faktoren, Technologiecharakteristika und Biomassekosten wider. Die Bandbreiten für Brennstoffzellen, PV-Anlagen und Erdgas-BHKW resultieren hauptsächlich aus den Anlagenleistungen; Werte für bestimmte Anlagenleistungen sind in den Technologiedatenblättern und den einzelnen Kapiteln angegeben. Kosten für Stromimporte mittels Gleichspannungsübertragung im Bereich von 0.5-2 Rp./kWh müssen addiert werden. Für Brennstoffzellen, Biomasse und Erdgas-BHKW sind Wärmegutschriften berücksichtigt. GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; KVA: Kehrichtverbrennungsanlage; CSP: "concentrated solar power"; EGS: "enhanced geothermal systems"; MC: "molten carbonate"; SO: "solid oxide"; PE: "polymer electrolyte"; PA: "phosphoric acid"; "Kohle" beinhaltet Stein- und Braunkohle.

Die Änderungen bei den heutigen Stromproduktionskosten im Vergleich zur vorangegangenen Studie sind sichtbar, jedoch nicht substanziell: Die heutigen Stromproduktionskosten von Windkraftwerken in der Schweiz bleiben in etwa gleich, während die Kosten von Strom aus Offshore-Turbinen in Europa (für Stromimporte) im Vergleich zur vorhergehenden Schätzung recht deutlich abnehmen. Die aktualisierten Kosten von Strom aus PV-Dachanlagen in der Schweiz sind etwas tiefer als vor zwei Jahren. Ebenso etwas tiefer sind die Stromproduktionskosten von Erdgaskraftwerken, -BHKW und -Brennstoffzellen, da die aktualisierten Erdgaspreise etwas tiefer sind als zuvor angenommen und sich auch technische Fortschritte bei Brennstoffzellen in den Stromproduktionskosten niederschlagen. Bei den erwarteten Stromproduktionskosten im Jahr 2050 weisen im Vergleich zur vorgängigen Schätzung

[14] Für Grosswasserkraftwerke und Kernkraftwerke werden auch die heutigen Stromproduktionskosten der aktuell in Betrieb stehenden Anlagen dargestellt (Kernkraft: KKW Gösgen und Leibstadt). Im Fall der Kernenergie beziehen sich die Kosten für „hypothetische Neuanlagen" auf Reaktoren der dritten Generation, deren Planung heute gestartet würde – Details in (Bauer et al. 2017).

Offshore-Windturbinen die markantesten Reduktionen auf, da die neuesten verfügbaren Literaturquellen deutlich optimistischer in ihren Kostenschätzungen sind. Für andere Technologien wurden die erwarteten Stromproduktionskosten im Jahr 2050 geringfügig nach unten korrigiert oder bleiben auf dem gleichen Niveau wie in der früheren Schätzung.

Hinsichtlich Datenqualität und Belastbarkeit der Ergebnisse ist gegenüber der vorangegangenen Studie vor allem bei Fotovoltaikanlagen eine deutliche Verbesserung festzuhalten. Das betrifft einerseits die Gesamtinvestitionskosten – das Sample an Anlagen, für die Investitionskosten verfügbar waren, war 2016 klein, während nun mehrere hundert Kostendatenpunkte aus dem Solar-Offerten-Check von EnergieSchweiz[15] zur Verfügung standen. Andererseits wurde in der vorgehenden Studie die Aufteilung der Kosten auf Module, Installation etc. von Grossanlagen auf alle Leistungsklassen übertragen, während nun auch spezifische Zahlen für Kleinanlagen zur Verfügung stehen. Somit sind die neuen Berechnungen deutlich verlässlicher und aussagekräftiger.

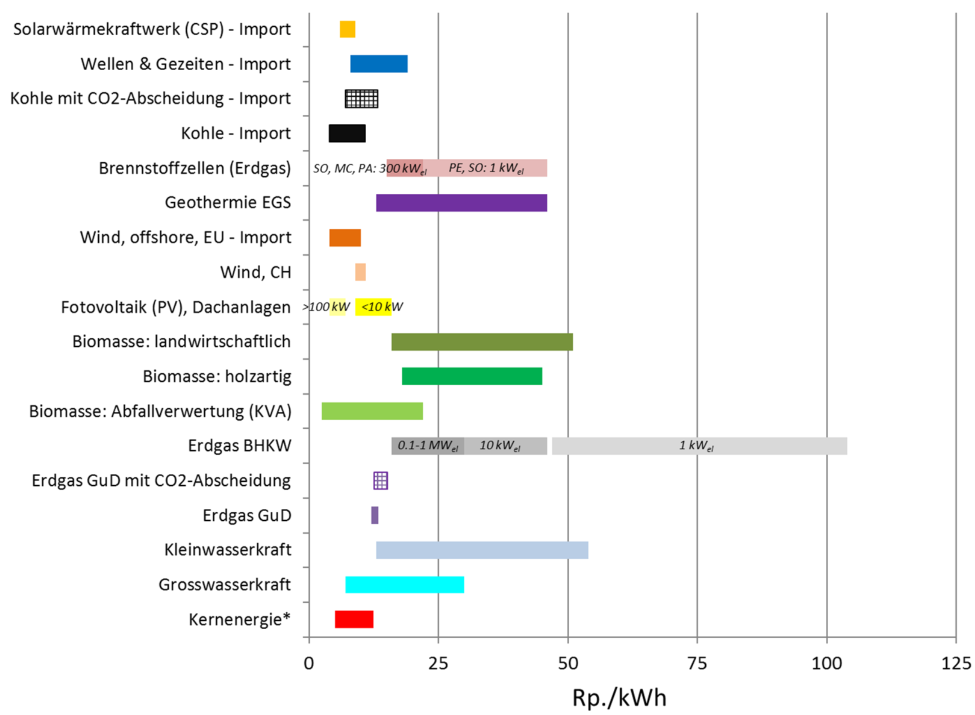

Abbildung 2.2: Geschätzte Stromproduktionskosten im Jahr 2050. Die dargestellten Bandbreiten spiegeln Variabilität aufgrund standortspezifischer Faktoren, Technologiecharakteristika, Biomassekosten und der erwarteten zukünftigen Technologiekosten wider. Die Bandbreiten für Brennstoffzellen, PV-Anlagen und Erdgas-BHKW resultieren hauptsächlich aus unterschiedlichen Anlagenleistungen; Werte für bestimmte Anlagenleistungen sind in den Technologiedatenblättern und den einzelnen Kapiteln angegeben. Kosten für Stromimporte mittels Gleichspannungsübertragung im Bereich von 0.5-2 Rp./kWh müssen addiert werden. Für Brennstoffzellen, Biomasse und Erdgas-BHKW sind Wärmegutschriften berücksichtigt, nicht aber für Geothermie.[16] LCOE: "Levelized costs of electricity"; GuD: Gas- und Dampfkraftwerk; BHKW: Blockheizkraftwerk; CSP: "concentrated solar power"; EGS: "enhanced geothermal systems"; MC: "molten carbonate"; SO: "solid oxide"; PE: "polymer electrolyte"; PA: "phosphoric acid"; "Kohle" beinhaltet Stein- und Braunkohle. *Die Kosten für Kernenergie gelten für Generation 3+ Reaktoren und so genannte „small modular reactors", da für Generation 4 Reaktoren, die 2050 eine Option sein könnten, keine belastbaren Zahlen vorliegen.

[15] https://www.energieschweiz.ch/page/de-ch/solar-offerte-check

[16] Der Einfluss von Profit aus dem Wärmeabsatz auf die wirtschaftliche Machbarkeit von EGS-Anlagen ist bedeutend, da wegen relativ kleiner elektrischer Wirkungsgrade grosse Mengen an (Ab-)Wärme produziert werden. Aus heutiger Sicht erscheint es vor allem aus Perspektive der Risikowahrnehmung unwahrscheinlich, dass Geothermie-Kraftwerke meist in der Nähe von grossen Wärmeabnehmern errichtet werden können. Details dazu siehe (Bauer et al. 2017).

3 Résumé

Les potentiels, les coûts et l'impact environnemental des technologies de production de l'électricité font périodiquement l'objet de relevés pour le compte de l'Office fédéral de l'énergie (OFEN) Le dernier relevé date de 2017 (Bauer *et al.* 2017, en anglais avec résumé en français). Entretemps, les coûts des modules photovoltaïques ont continué à baisser ; en outre le potentiel de production d'électricité au moyen d'installations photovoltaïques sur les toits en Suisse et le potentiel de la force hydraulique a été actualisé. Vue ceci, l'OFEN a mandaté le PSI pour qu'il procède à l'actualisation du coût de revient des technologies dont on présume qu'il a fondamentalement changé depuis 2017. Il s'agit essentiellement du photovoltaïque et des installations éoliennes *offshore* européennes. Les coûts de production de l'électricité par des centrales à énergie fossile (centrale à gaz à cycle combiné, couplage chaleur-force [CCF] et pile à combustible) ont été adaptés en fonction des composantes de prix actuelles pour le gaz naturel. Comme c'était le cas dans la précédente étude, les coûts actualisés de production d'électricité *(«levelised costs of electricity», LCOE)* ont d'abord été établis (année de référence: 2018), puis une estimation de l'évolution des coûts jusqu'en 2050 a été faite. Pour les autres technologies (chap. 10), qui n'entrent pas dans le cadre de ce rapport, on part du principe que les coûts établis dans l'étude antérieure demeurent d'actualité. Les *LCOE* de ces technologies ne sont indiqués dans les graphiques comparatifs que dans un souci d'exhaustivité; les données détaillées figurent dans le rapport précédent (Bauer *et al.* 2017). Tous les chiffres figurent dans les fiches de données spécifiques aux technologies (chap. 3).

En plus de l'actualisation des coûts de production d'électricité, des courbes coût-potentiel ont été établies pour les installations photovoltaïques placées sur les toits. Ces courbes montrent la quantité d'électricité pouvant être produite au moyen de cette technologie et les coûts correspondants. Elles ont été dessinées en combinant les nouvelles composantes de coûts avec les informations récemment mises à disposition sur les surfaces de toit disponibles dans «toitsolaire.ch». Elles représentent le potentiel technique pour la production d'électricité par des installations photovoltaïques sur les toits recensés en Suisse pour un coût de production donné. D'après les données sur les surfaces de toit disponibles, le potentiel technique pour la production d'électricité solaire en Suisse peut atteindre 63 TWh par an (sans les façades). Les coûts baissant, le potentiel économique va très nettement augmenter à l'avenir. Si l'on fixe le seuil de rentabilité à 15 ct./kWh et tient compte des coûts d'investissement actuels et de la surface nécessaire aux installations, le potentiel technico-économique sur les toits avoisine les 10 TWh par an; comme les coûts et la surface nécessaire vont se réduire, ce potentiel est estimé à un peu plus de 50 TWh pour l'année 2035. Si le seuil de rentabilité est abaissé à 11 ct./kWh, le potentiel technico-économique devrait atteindre environ 21 TWh en 2035. Si ce seuil est fixé à 13 ct./kWh, la production pourrait s'élever à 30 TWh. Ce sont les conditions-cadres qui détermineront la quantité d'électricité pouvant effectivement être produite.

Aussi les chiffres les plus récents de l'OFEN sur le développement de la force hydraulique ont été intégrés dans ce rapport. Le potentiel total de développement de la force hydraulique (grandes et petites installations hydroélectriques) d'ici à 2050 atteint désormais 540 à 2160 GWh par an. Dans l'étude de 2017, les estimations faisaient état d'un potentiel de développement supplémentaire de 1530 à 3160 GWh par an. Or, la quantité de production attendue aujourd'hui dépasse déjà de 640 GWh par an celle de 2012. La principale différence par rapport à 2012 est le fait que le potentiel des petites installations hydroélectriques a baissé d'environ 1000 GWh par an en raison des mesures d'encouragement qui arrivent à leur terme. Si l'on part d'une production nette moyenne de 35 990 GWh par an au 1er janvier 2019, on obtient une production attendue se situant dans une fourchette de 36 530 à 38 150 GWh en 2050. La fonte des glaciers due au changement climatique en cours va entraîner la formation de lacs, qui pourraient aussi être exploités dans le domaine de l'hydraulique. Selon les estimations de l'OFEN, ce potentiel supplémentaire pourrait atteindre 700 GWh par an.

Dans l'illustration 3.1, les coûts de la production d'électricité actuelle sont exposés pour les différentes technologies. Les coûts présentés ici reposent sur les données actualisées documentées aux chap. 7 à 9 et, pour les autres technologies, sur les chiffres repris, qui restent d'actualité (Bauer *et al.* 2017). Dans l'illustration 3.2, ces mêmes coûts sont représentés pour l'année 2050.

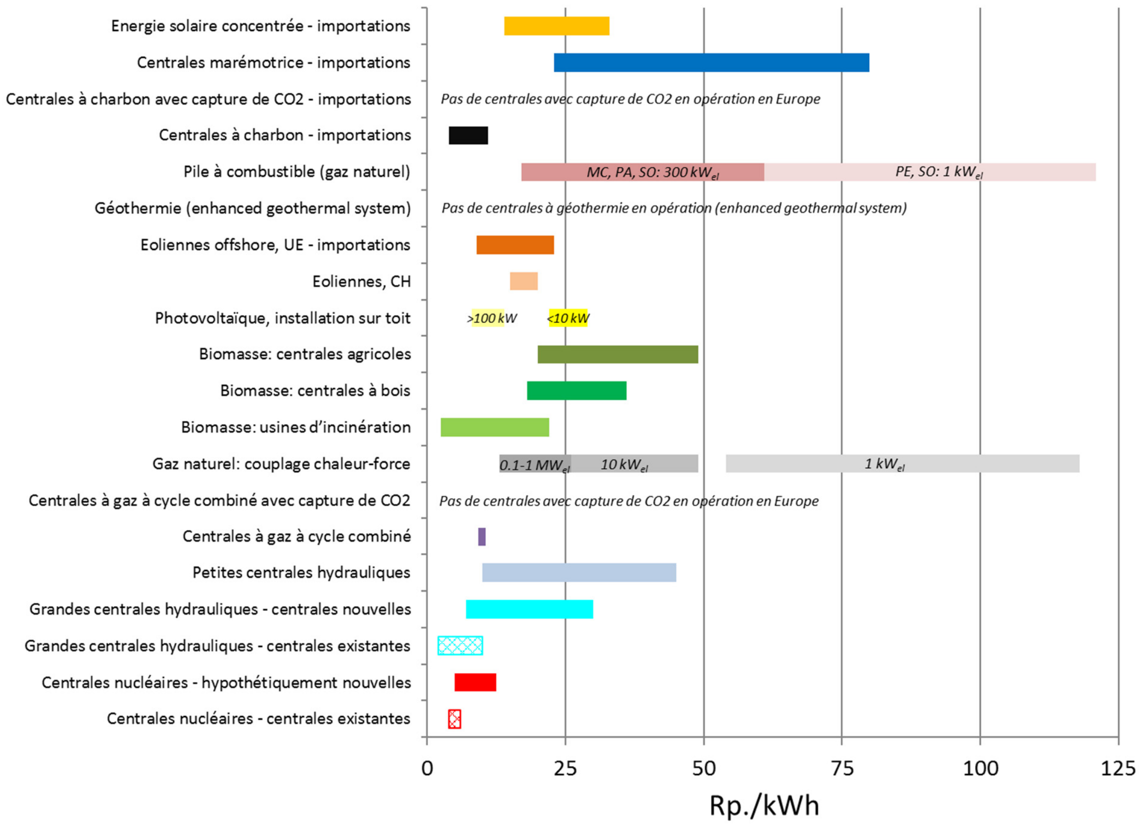

Illustration 3.1 : Coûts de la production d'électricité actuelle (année de référence 2018). Les fourchettes indiquées reflètent la variabilité due aux facteurs spécifiques aux sites, aux caractéristiques des technologies et aux coûts de la biomasse. Les fourchettes pour les piles à combustible, les installations photovoltaïques et les CCF fonctionnant au gaz naturel dépendent essentiellement de la puissance des installations; les valeurs pour certaines puissances des installations figurent dans les fiches de données et les chapitres spécifiques aux technologies. Les coûts des importations d'électricité en courant continu, de l'ordre de 0,5 à 2 ct./kWh, doivent être ajoutés. Pour les piles à combustible, la biomasse et les CCF fonctionnant au gaz naturel, les crédits attribués pour l'exploitation des rejets de chaleur sont pris en compte. GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: énergie solaire concentrée (*concentrated solar power*); EGS: géothermie (*enhanced geothermal systems*); MC: carbonate fondu (*molten carbonate*); SO: oxyde solide (*solid oxide*); PE: électrolyte polymère (*polymer electrolyte*); PA: acide phosphorique (*phosphoric acid*); le «charbon» comprend la houille et le lignite.

Les modifications survenues entre les coûts de la production d'électricité selon l'étude précédente et les coûts actuels sont visibles, mais ne sont pas substantielles: les coûts de production d'électricité actuels par les éoliennes en Suisse demeurent à peu près les mêmes. Par contre, le coût de l'électricité provenant de turbines *offshore* en Europe (pour les importations d'électricité) diminue fortement par rapport à l'estimation antérieure. Les coûts actualisés de l'électricité provenant d'installations photovoltaïques placées sur les toits en Suisse ont légèrement diminué ces deux dernières années. Les coûts de production d'électricité dans les centrales au gaz naturel, les CCF au gaz naturel et les piles à combustible fonctionnant au gaz naturel sont également un peu plus faibles: en effet, le prix du gaz naturel actualisé est légèrement inférieur aux estimations précédentes et les progrès techniques dans les piles à combustible se sont répercutés sur les prix de production de l'électricité. En ce qui concerne les coûts de production d'électricité attendus en 2050, par rapport à l'estimation antérieure, les turbines éoliennes *offshore* affichent les réductions les plus marquées, car les sources documentaires les plus récentes sont nettement plus optimistes dans leurs estimations de coûts. S'agissant des autres technologies, les coûts de production d'électricité attendus en 2050 ont été légèrement corrigés à la baisse ou demeurent au niveau de la précédente estimation.

Pour ce qui est de la qualité des données et de la fiabilité des résultats, on note une nette amélioration par rapport à l'étude antérieure, en particulier pour les installations photovoltaïques. D'une part, l'échantillon d'installations disponibles pour les coûts d'investissement totaux était limité en 2017 alors que, pour la présente étude, plusieurs centaines de points de données relatifs aux coûts provenant de l'outil Check-devis-solaire de SuisseEnergie étaient disponibles. D'autre part, dans l'étude précédente, la ventilation des coûts (modules, installation, etc.) concernant les grandes installations était appliquée à toutes les classes de puissance, tandis que maintenant, des chiffres spécifiques sont aussi disponibles pour les petites installations. Ainsi, les nouveaux calculs sont sensiblement plus fiables et plus parlants.

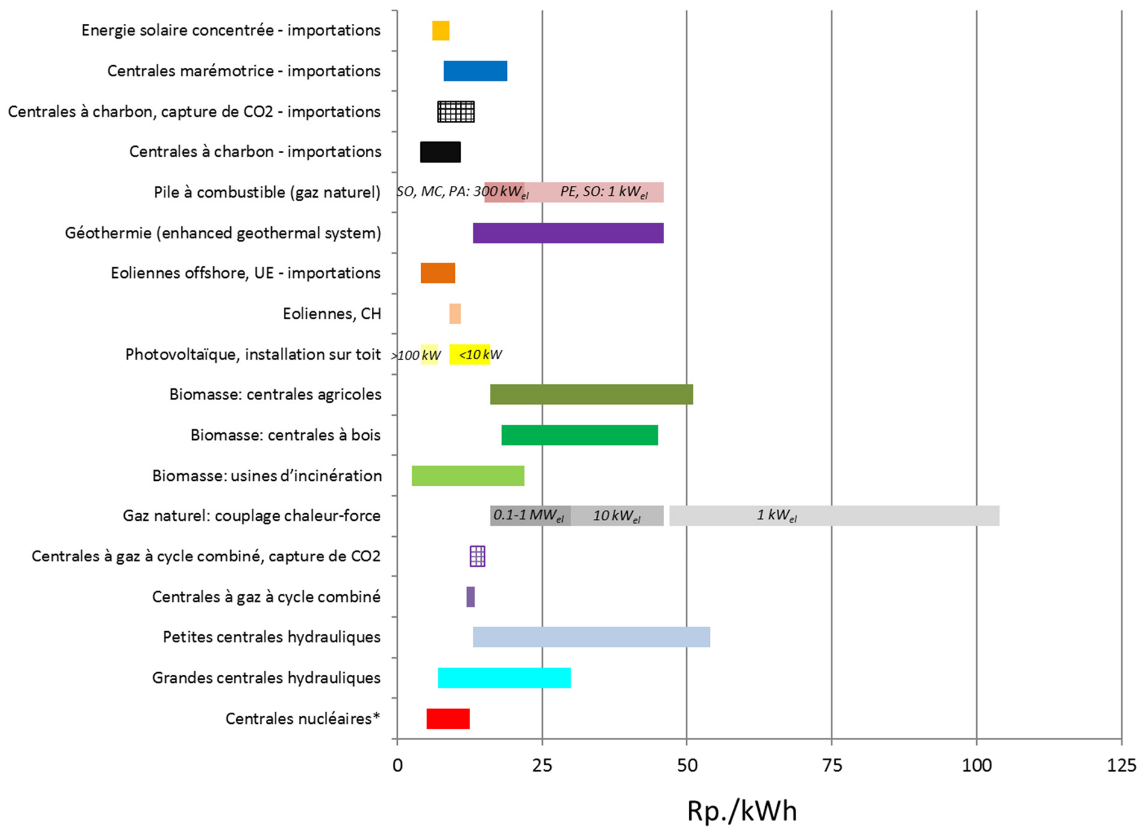

Illustration 3.2 : Estimation des coûts de la production d'électricité en 2050. Les fourchettes indiquées reflètent la variabilité due aux facteurs spécifiques aux sites, aux caractéristiques de la technique, aux coûts de la biomasse et aux coûts technologiques escomptés. Les fourchettes pour les piles à combustible, les installations photovoltaïques et les CCF fonctionnant au gaz naturel résultent principalement des différences de puissance des installations; les valeurs pour certaines puissances figurent dans les fiches de données et les chapitres spécifiques aux technologies. Les coûts des importations d'électricité en courant continu, de l'ordre de 0,5 à 2 ct./kWh, doivent être ajoutés. Les crédits attribués pour l'exploitation des rejets de chaleur sont pris en compte pour les piles à combustible, la biomasse et les CCF au gaz naturel, mais pas pour la géothermie. LCOE: coûts actualisés de production d'électricité *(levelised costs of electricity)*; GuD: centrale à gaz à cycle combiné; CCF: couplage chaleur-force; CSP: énergie solaire concentrée *(concentrated solar power)*; EGS: géothermie *(enhanced geothermal systems)*; MC: carbonate fondu *(molten carbonate)*; SO: oxyde solide *(solid oxide)*; PE: électrolyte polymère *(polymer electrolyte)*; PA: acide phosphorique *(phosphoric acid)*; le «charbon» comprend la houille et le lignite. *Les coûts de l'énergie nucléaire sont valables pour les réacteurs de génération 3+ et les petits réacteurs modulaires *(small modular reactors)*, car on ne dispose pas de chiffres exploitables pour les réacteurs de génération 4, qui pourraient être une option en 2050.

4 Sintesi

L'Ufficio federale dell'energia (UFE) rileva regolarmente il potenziale, i costi e l'impatto ambientale delle tecnologie per la produzione di energia elettrica. L'ultimo rilevamento risale al 2017 (Bauer et. al. 2017); nel frattempo, i costi per i moduli fotovoltaici sono ulteriormente diminuiti. Inoltre sono disponibili nuove basi per il calcolo del potenziale degli impianti fotovoltaici sui tetti in Svizzera[17] e anche il potenziale di energia idroelettrica è cambiato. Alla luce di ciò, l'UFE ha incaricato l'Istituto Paul Scherrer di adeguare i costi di produzione delle tecnologie per le quali sono stati ipotizzati mutamenti significativi dal 2017. Si tratta essenzialmente del fotovoltaico e degli impianti eolici offshore europei. Anche i costi di produzione delle centrali termoelettriche a combustibili fossili (centrali a gas a ciclo combinato, impianti di cogenerazione di energia elettrica e termica e pile a combustibile) sono stati adattati sulla base degli attuali dati relativi al prezzo del gas naturale. Come nello studio precedente, sono riportati i costi di produzione dell'energia elettrica odierni (anno di riferimento: 2018), calcolati secondo il metodo dei «levelized costs of electricity» (LCOE), e sulla base di ciò, una stima dell'evoluzione dei costi fino al 2050. Per altre tecnologie che non fanno parte di questo rapporto (cfr. capitolo 10) si ipotizza che i dati relativi ai costi pubblicati nello studio precedente siano ancora validi. I costi relativi a queste tecnologie, calcolati secondo il metodo LCOE, sono presentati sotto forma di grafici comparativi. Questo permette di averne una panoramica completa[18]; dettagli sono disponibili nello studio precedente (Bauer et. al. 2017)[19]. Tutte le cifre sono disponibili nelle schede tecniche delle singole tecnologie (cfr. capitolo 3).

A complemento dell'adeguamento dei costi di produzione dell'energia elettrica, nel presente studio sono state create delle curve che indicano il rapporto tra i costi e il potenziale degli impianti fotovoltaici sui tetti. Tali curve mostrano quanto costa produrre una determinata quantità di energia con tali impianti. Gli ultimi dati sui costi sono stati combinati con le nuove informazioni a disposizione riguardanti le superfici dei tetti disponibili (cfr. piattaforma www.tettosolare.ch) e rappresentano il potenziale tecnico teoricamente sfruttabile per la produzione di energia elettrica con impianti fotovoltaici sui tetti in Svizzera, per determinati costi di produzione. Secondo i dati relativi alle superfici dei tetti disponibili[20], il potenziale tecnico teoricamente sfruttabile per la produzione di energia solare in Svizzera è pari a 63 TWh all'anno (escluse le facciate). In futuro il potenziale economico crescerà molto grazie alla riduzione dei costi: con gli attuali costi di investimento e lo specifico fabbisogno di superficie degli impianti, impostando il «limite di redditività» a 15 ct./kWh, si ottiene un potenziale tecnico-economico dei tetti di circa 10 TWh/a. Questo valore tenderà ad aumentare grazie alla diminuzione dei costi e al minore fabbisogno di superficie, nel 2035 si attesterà a circa 50 TWh/a. Impostando un «limite di redditività» inferiore, pari a 11 ct./kWh, si ottiene invece un potenziale tecnico-economico di circa 21 TWh per il 2035. Una produzione annuale di 30 TWh può essere realizzata al costo di circa 13 ct./kWh[21]. Quanto sarà effettivamente possibile produrre dipende dalle rispettive condizioni quadro.

Sono stati inseriti anche gli ultimi dati dell'UFE relativi all'incremento dell'energia idroelettrica. Il potenziale di sviluppo complessivo dell'energia idroelettrica (centrali idroelettriche piccole e grandi) fino al 2050 si aggira tra i 540 e i 2160 GWh/a. Nello studio del 2017 era ancora stato stimato un potenziale d'incremento di 1530-3160 GWh/a[22], tuttavia la quantità prodotta attesa supera già di 640 GWh/a il valore del 2012. La differenza principale rispetto al 2012 sta nel fatto che il potenziale delle piccole centrali idroelettriche è diminuito di circa 1000 GWh/a a causa della promozione che sta giungendo al termine. Sulla base della produzione netta media del 1° gennaio 2019, pari a 35 990 GWh/a, la produzione prevista per il 2050 è compresa tra i 36 530 e i 38 150 GWh/a. In seguito

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[17] www.tettosolare.ch
[18] Una combinazione di tecnologie è decisiva per promuovere lo sviluppo delle energie rinnovabili.
[19] I dati aggiornati sono disponibili in rosso.
[20] Fonte: https://www.uvek-gis.admin.ch/BFE/sonnendach/?lang=it/
[21] Tutti i dati concernenti gli impianti fotovoltaici sono calcolati con un fattore di sfruttamento dei tetti del 70 %.
[22] Basato su UFE 2012.

ai progressivi cambiamenti climatici, i ghiacciai si riducono e si creano i laghi glaciali, che possono anche essere utilizzati per l'energia idroelettrica. L'UFE prevede che questo potenziale supplementare si aggirerà a attorno ai 700 GWh/a.

Nella figura 4.1 sono illustrati i costi di produzione dell'energia elettrica odierni delle varie tecnologie, mentre nella figura 4.2 quelli previsti per il 2050. Tali costi si basano su adeguamenti documentati e su dati ancora validi (Bauer et. al. 2017) per le restanti tecnologie, presentati nei capitoli 7-9.

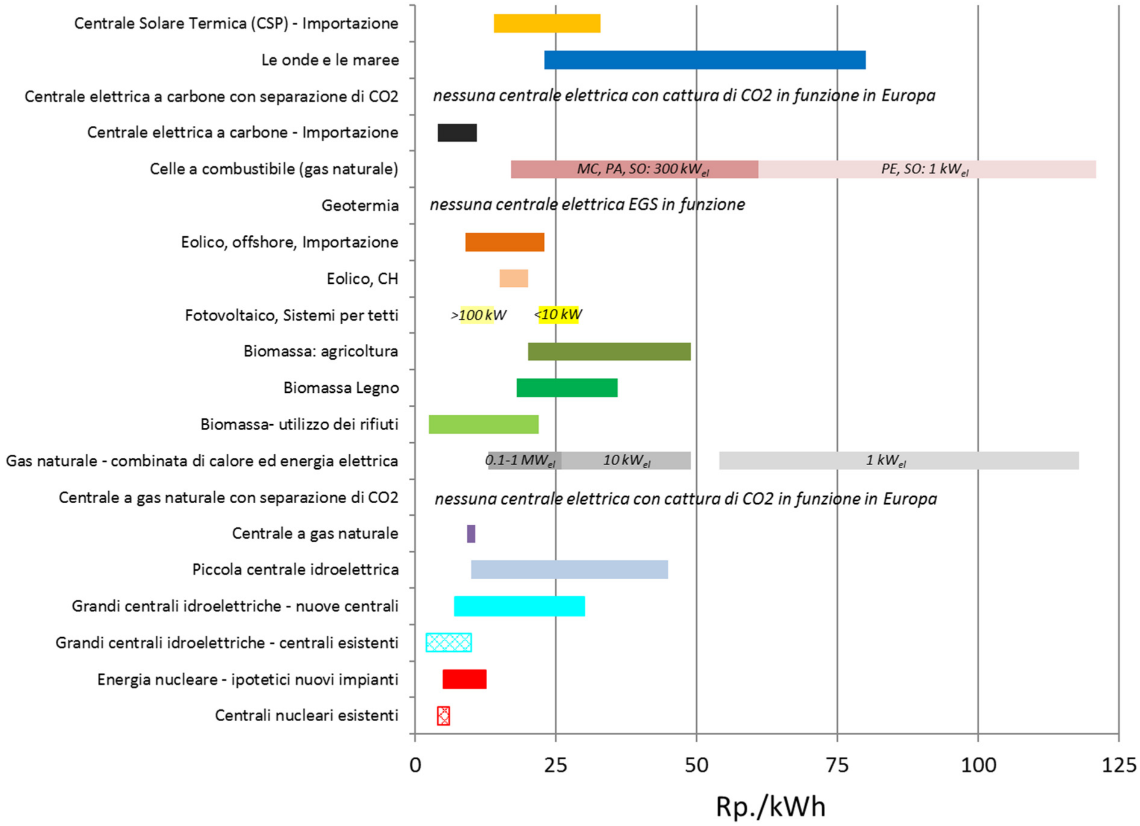


Figura 4.1: costi di produzione dell'energia elettrica odierni (anno di riferimento: 2018) . I margini di oscillazione esposti rispecchiano la variabilità dei costi di produzione a seconda delle condizioni locali specifiche, del tipo di tecnologia e dei costi della biomassa. I margini di oscillazione per le pile a combustibile, gli impianti fotovoltaici e le CTEB funzionanti a gas naturale dipendono principalmente dalla potenza degli impianti; valori relativi a determinante potenze degli impianti sono disponibili nelle schede tecniche delle varie tecnologie e nei singoli capitoli del rapporto. Vanno aggiunti i costi per le importazioni di energia elettrica mediante la trasmissione a corrente continua, di importo compreso tra 0,5 e 2 ct./kWh. Per le pile a combustibile e per le CTEB funzionanti a biomassa e a gas naturale si è tenuto conto dei ricavi risultanti dal calore. Centrali a gas a ciclo combinato; centrali termoelettriche a blocco (CTEB); impianti di incenerimento dei rifiuti urbani (IIRU); «concentrated solar power» (CSP); «enhanced geothermal systems» (EGS); «molten carbonate» (MC); «solid oxide» (SO); «polymer electrolyte» (PE); «phosphoric acid» (PA); il termine «carbone» comprende carbone fossile e lignite.

Le variazioni tra i costi di produzione dell'energia elettrica odierni e quelli del precedente studio sono evidenti ma non sostanziali: i costi di produzione dell'energia elettrica delle centrali a energia eolica in Svizzera sono rimasti pressoché invariati, mentre i costi dell'energia elettrica delle turbine offshore in Europa (per l'importazione di energia elettrica) sono diminuiti notevolmente rispetto alle precedenti previsioni. Oggi i costi di produzione dell'energia elettrica degli impianti fotovoltaici sui tetti in Svizzera sono leggermente inferiori rispetto a due anni fa, stessa cosa vale per i costi di produzione dell'energia elettrica delle centrali a gas, delle centrali termoelettriche a blocco (CTEB) e delle pile a combustibile, visto il leggero calo del prezzo del gas naturale rispetto a quanto previsto e grazie ai progressi tecnici concernenti le pile a combustibile. Rispetto alla stima precedente, i costi di produzione dell'energia elettrica delle turbine eoliche offshore previsti per il 2050 presentano le diminuzioni più significative, poiché le nuove fonti di riferimento disponibili sono decisamente più ottimiste nelle loro stime dei costi. I costi di produzione dell'energia elettrica previsti per il 2050 per le altre tecnologie hanno subito una leggera riduzione o sono rimaste allo stesso livello rispetto alla precedente previsione.

Rispetto allo studio precedente, la qualità dei dati e l'affidabilità dei risultati registrano un chiaro miglioramento in particolare per quanto riguarda gli impianti fotovoltaici. Da una parte, ciò riguarda il costo totale degli investimenti: nel 2016 il campione di impianti per i quali erano disponibili dati relativi ai costi di investimento era ridotto, mentre ora sono disponibili centinaia di dati grazie al Check-preventivo-solare di SvizzeraEnergia . D'altra parte, nello studio precedente, la ripartizione dei costi (moduli, installazione ecc.) per i grandi impianti era stata applicata a tutte le classi di potenza, mentre ora sono disponibili anche dati specifici riguardanti i piccoli impianti. In questo modo le stime sono ora più affidabili e significative.

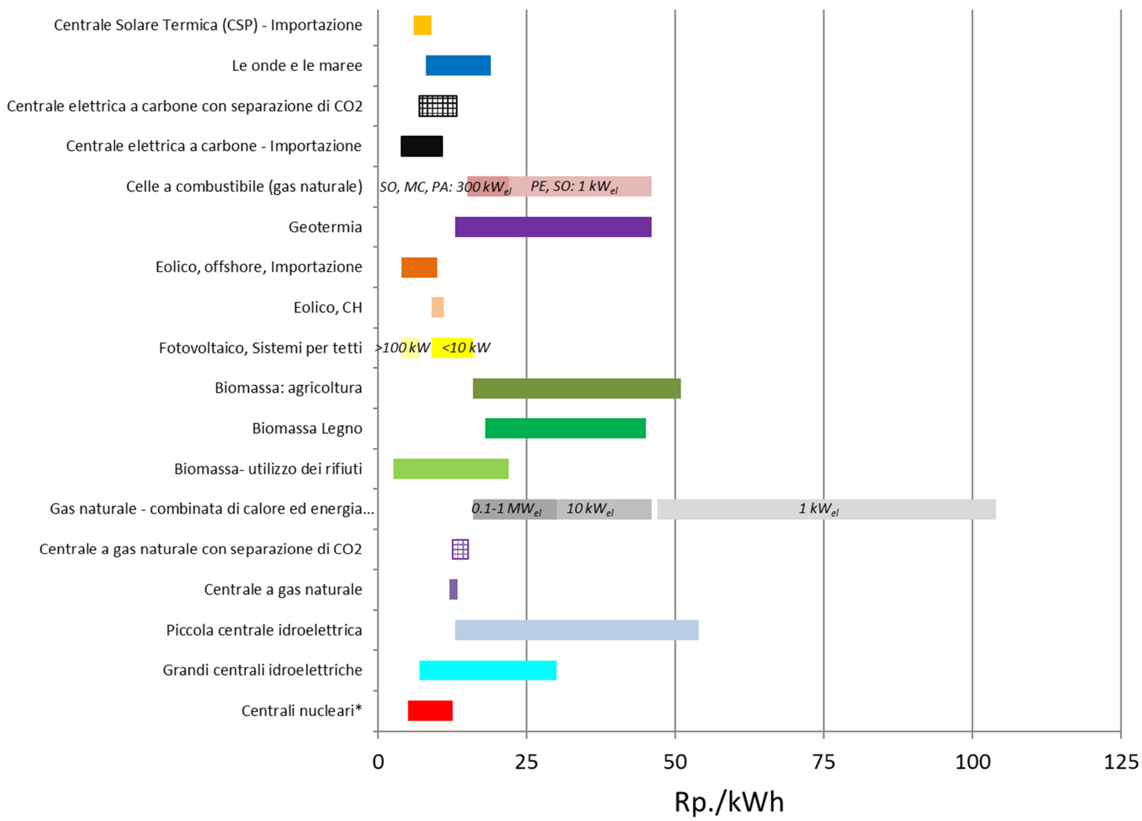


Figura 4.2: costi di produzione dell'energia elettrica stimati per il 2050. I margini di oscillazione esposti rispecchiano la variabilità dei costi di produzione a seconda delle condizioni locali specifiche, del tipo di tecnologia, dei costi della biomassa e dei costi della tecnologia previsti per il futuro. I margini di oscillazione per le pile a combustibile, gli impianti fotovoltaici e le CTEB funzionanti a gas naturale dipendono principalmente dalla potenza degli impianti; i valori relativi alle determinate potenze degli impianti sono disponibili nelle schede tecniche delle varie tecnologie e nei singoli capitoli del rapporto. Vanno aggiunti i costi per le importazioni di energia elettrica mediante la trasmissione a corrente continua, di importo compreso tra 0,5 e 2 ct./kWh. Per le pile a combustibile e le CTEB funzionanti a biomassa e a gas naturale si è tenuto conto dei ricavi risultanti dal calore. Ciò non è stato fatto per la geotermia . «Levelized costs of electricity» (LCOE: costi sistemici totali livellati); centrali a gas a ciclo combinato; centrali termoelettriche a blocco (CTEB); «concentrated solar power» (CSP); «enhanced geothermal systems» (EGS); «molten carbonate» (MC); «solid oxide» (SO); «polymer electrolyte» (PE); «phosphoric acid» (PA); il termine «carbone» comprende carbone fossile e lignite. *I costi dell'energia nucleare valgono per i reattori di generazione 3+ e per i cosiddetti «small modular reactors», poiché per i reattori di generazione 4, che potrebbero essere un'opzione nel 2050, non vi sono dati disponibili.

5 Data sheets

The following fact sheets summarize the key figures for each technology, for which updates compared to (Bauer et al. 2017) have been performed: hydropower, wind power, photovoltaics, and natural gas combined cycle and cogeneration plants as well as fuel cells. Electricity generation potentials have only been updated for roof-top photovoltaic modules and hydropower. Updated numbers in the fact sheet tables are highlighted in red.

Data sheet – Large hydropower (LHP)

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities above 10 MW average gross capacity are categorized as "large" in Switzerland. Depending on the way water is used, hydropower plants can be categorized as:

- Storage power plants: Water is dammed up with a dam in a reservoir, fed via a pressure pipe to a turbine and turbined there.
- Run-of-river power plants: The water flows directly from the river to a turbine or is dammed with a dam and then led via a discharge channel/pressure line to a turbine further downstream (discharge power station).
- Pumped storage power plants: supplying peak power by moving water between reservoirs at different elevations using pumps.

LHP plants represent mature technology. Turbine efficiencies are not expected to increase substantially in the future.

LHP		New power plants: current[1]		2020	2035	2050
Potential[2] (expected average, renewable production)	TWh/a	31.9[10]		~32.0	33.6-34.8	33.6-34.8[11]
					32.5-34.2	32.5-33.6[11]
Investment costs[3]	CHF/kW	3'500 (2'000-10'000)		2'000-10'000	2'000-10'000	2'000-10'000
Electricity generation costs[4,5]	Rp./kWh	Run-of-river[8] / Storage[9]	7-30	7-30	7-30	7-30
GHG emissions[6,7]	g CO_2eq./kWh	Run-of-river	5-10	~5-10	~5-10	~5-10
		Storage	5-15	~5-15	~5-15	~5-15

[1] "current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current annual average expected renewable electricity production as of 1.1.2019 (expected production minus consumption of pumps; actual production varies from year to year depending on rainfall, climate, etc.).

[2] According to (SFOE 2019). Expansion and its speed beyond 2020 will predominantly depend on the economic boundary condition and social acceptance of new LHP. Around 700 million CHF in investment contributions will be available by 2030 for the expansion of Switzerland's large hydroelectric power plants. New constructions and renovations/extensions of existing power plants are supposed to contribute about equally to increasing generation. For 2035 and 2050, the upper row represents the technical potential without considering new legislation ("Gewässerschutzgesetz"); the lower row takes into account reduction of LHP generation of 1'170 GWh/a (overall reduction: 1'300 GWh/a; 90% assigned to LHP, 10% to small hydropower in proportion to current generation) due to effects of new legislation.

[3] Available data do not allow for differentiation between storage and run-of-river power plants. 3'500 CHF/kW represents a generation weighted average of potential additional LHP generation (new constructions and extensions of existing plants) excluding projects focusing on modification of hydropeaking.

[4] Generation costs include investment, operation & maintenance and other costs. Ranges provided represent variability due to site-specific aspects. Details concerning data used and sensitivities can be found in the report.

[5] Assuming that the economically more attractive power plant sites would be exploited first, electricity generation costs from new plants would increase from the lower range of the interval provided for today to the higher range in 2050. In total, additional 1.6 TWh/a (not considering the effect of new legislation ("Gewässerschutzgesetz")) can be generated with production costs below 15 Rp./kWh.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided are supposed to reflect potential variability of performance due to site-specific conditions. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 g CO_2-eq./kWh (high voltage).

[7] Environmental burdens are assumed to stay constant in the future, since LCA burdens of LHP are comparatively minor and technology development with substantial impact on LCA results of LHP is unlikely.

[8] LCOE of currently operating plants with partially amortized investments: 5-6 (2-10) Rp./kWh.
[9] LCOE of currently operating plants with partially amortized investments: 6 (3-9) Rp./kWh.
[10] 35.9 TWh/a average, renewable expected generation as of 1.1.2019 reduced by 4 TWh/a generated by small hydro according to the small hydro statistics from Swiss Small Hydro.
[11] As climate change progresses, glaciers will shrink, creating glacial lakes that may be used for hydropower. The SFOE (SFOE 2019) estimates this additional potential at around 700 GWh/a; however, whether and to which extent this generation potential can be realized, is highly uncertain and therefore, this amount is not included in the figures.

Data sheet – Small hydropower (SHP)

Technology: Hydropower plants generate power by converting kinetic or potential energy of water into electricity. Power plants with capacities below 10 MW are categorized as "small" in Switzerland. Power plants with capacities below 300 kW are often referred to as "mini hydropower" plants. SHP plants can also be integrated in existing infrastructure, such as drinking water pipes. Depending on the way the water is used, SHP plants can be categorized as:

- Storage power plants: including a dam and a storage reservoir lake
- Run-of-river power plants: without a dam; the hydrological regime remains unchanged

Small hydropower plants represent mature technology. Current turbine efficiencies are not expected to increase substantially in the future. However, current research aims at providing new and more efficient solutions for medium head and low-head respectively low-runoff applications in order to make more sites exploitable.

SHP		New power plants: current[1]		2020	2035	2050
Potential[2]	TWh/a		4.0	4.0	~4.0-4.4	~4.0-4.4
Investment costs[3]	CHF/kW	Diversion/ Run-of-river	6'160 (5'200-13'700)	~6'160	~7'150	~7'400
		Drinking water	11'150 (9'600-25'100)	~11'150	~13'000	~13'400
Electricity generation costs[4,5]	Rp./kWh	Diversion/ Run-of-river	12-28	~12-28	~14-33	~14-34
		Drinking water	17-42	~17-42	~20-49	~20-50
GHG emissions[6,7]	g CO_2eq./kWh	Diversion/ Run-of-river	~5-10	~5-10	~5-10	~5-10
		Drinking water	~2-5	~2-5	~2-5	~2-5

[1] "current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today; current potential refers to current expected, annual renewable electricity production as of 1.1.2019 (actual production varies from year to year depending on rainfall, climate, etc.).

[2] The range for future potentials reflects the variety of estimates in literature (SFOE 2019). The SFOE estimates additional potential of 110-550 GWh/a (other sources slightly more or less). These numbers are supposed to be reduced by ~130 GWh/a as an effect of new legislation ("Gewässerschutzgesetz"). Actual implementation of new SHP plants will depend on future funding schemes.

[3] Estimates for current investment costs are based on SHP data in the "KEV-list" (cost-covering feed-in remuneration). The analyzed sample of new SHP constructions covers 1049 SHP projects. Future investment costs are supposed to increase due to exhaustion of favorable SHP sites and tightening of environmental regulations.

[4] Generation costs include investment, operation & maintenance and other costs. Electricity generation costs of SHP strongly depend on site-specific boundary conditions and have to be evaluated on a case-by-case basis.

[5] Assuming that the economically more attractive sites would be exploited first, future electricity generation costs would increase from the lower range of the interval provided in 2020 to the higher range in 2050.

[6] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and variations in power plant lifetime. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100 g CO_2eq./kWh (low voltage).

[7] Environmental burdens are assumed to stay about constant in the future, since burdens of SHP are minor and major technology development with substantial impact on the environmental performance of SHP is unlikely.

Data sheet – Wind power

Technology: Horizontal axis wind turbines (HAWT) are dominating the world market. Kinetic energy from moving air is harvested and turned into electrical due to rotation of blades. Today's wind turbines can exploit wind speeds of 3-34 m/s.

Wind power			New power plants: Current[10]	2020	2035	2050
Capacity		Onshore	1-3 MW (70% of installed capacity); new turbines: 2-4 MW	Largest turbines today: 8 MW (on-/ offshore), 164 m rotor diameter, 220 m hub height. Feasibility of 20 MW turbines demonstrated.		
		Offshore	>3 MW (2/3 of installed capacity)			
Capacity factor (cf)[1]		General	0.1-0.55 World average ~0.23 (2013)	Capacity factors are expected to increase slightly due to technological improvements at the level of the wind turbine as well as wind speed forecasting and improved placement of wind turbines.		
		Onshore	CH: 0.21; Germany: 0.22 (2015)			
		Offshore	Up to 0.55			
Potential[11]	TWh/a	Switzerland	0.1	0.1 - 0.6	0.7 - 1.7	1.4 - 4.3
	TWh/a	Europe[6]	~260	580-630	2030: 604-988	No data available
Electricity generation costs[2,3,11]	Rp./kWh	Switzerland	15 - 20	15 - 20	10 - 15	9 - 13
		Europe, onshore	4 - 15	4 - 15	3 - 11	3 - 10
		Europe, offshore[7]	9 - 16	9 - 16	5 - 12	5 - 12
GHG emissions[4,5,2]	g CO_2-eq./kWh	Switzerland	~15 (8 - 27)	5 - 30	5 - 30	5 - 30
		Europe, onshore[8]	8 - 21	5 - 25	5 - 25	5 - 25
		Europe, offshore[9]	8 - 16	5 - 20	5 - 20	5 - 20

[1] Annual "full load hours" divided by 8760 h/a. Annual full load hours are calculated as the time of the year, which a turbine would operate at its rated capacity in order to generate the annual electricity output.
[2] Generation costs include investment, operation & maintenance and other costs. The annual yield is the most important factor for both electricity generation costs and LCA results; intervals in this table represent typical yields in Switzerland and Europe, respectively. At sites with very favorable/unfavorable wind conditions, figures can be outside of the ranges provided here.
[3] Future cost estimates represent rough estimates based on scarce literature and recent trends in cost development, not taking into account potential substantial changes in commodity prices.
[4] Greenhouse gas emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided reflect potential variability of performance due to site-specific conditions and turbine technology. For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 90 g $CO_{2eq.}$/kWh (high voltage).
[5] Environmental impacts are not expected to change substantially. A decrease would mainly be due to better exploitation of the wind resource. An increase would mainly be due to reduced availability of good sites.
[6] Based on the available data, differentiation between future onshore and offshore generation is not possible.
[7] Intervals estimated according to EU-specific literature sources in Figure 9.5; 1.15 CHF/€.
[8] Estimated using capacity factors of 0.15-0.35.
[9] Based on the ecoinvent database, v3.3, "allocation – cut-off by classification". Estimated with cf of 0.30-0.55.
[10] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants (theoretically) built in 2018 or 2020 – planning procedures for such turbines in Switzerland would have started several years ago due to long permission periods and therefore, such projects could not profit from recent technology development resulting in LCOE reductions only for turbines installed around 2030.
[11] According to (suisseéole 2019b), wind speeds modeled for the Swiss "Windatlas" (www.windatlas.ch – used as reference for the federal wind energy concept), are partially substantially underestimated. Therefore, potential and LCOE could be under- and overestimated, respectively, to some extent.

Data sheet – Photovoltaics (PV)

Technology: Photovoltaic modules directly convert solar irradiance into electricity. Roof-top PV installations are most common in Switzerland. PV technology can be categorized as follows:

- 1st generation: crystalline Silicon cells (single-c Si and multi-c Si); on the market today
- 2nd generation: thin-film technologies – CdTe, amorphous Si, CIGS; on the market today
- 3rd generation: concentrating PV, dye-sensitized PV and organic PV; in research and development

Technology development focuses on increase of efficiencies and reduction of manufacturing costs.

Photovoltaics			**New power plants**			
			Current[7]	**2020**	**2035**	**2050**
Potential	Roof-top	TWh/a	1.68[8]	2.7[9]	24.6[10] (22-54)[11]	
	Facades	TWh/a			5.6[10] 17[12]	
Key technical parameters[1]	Solar irradiation (kWh/m²/a)		Switzerland (average of installed modules today): 1267			
	Efficiency	Module (%)	17	17-19	20-27	24-27
		Inverter (%)	98			
	Area per kW_p installed PV module capacity (m^2/kW_p)		6	5.4-6.2	3.8-5.0	3.8-5.0
	Performance ratio (%)		80			
	Swiss average annual yield[2] ($kWh/kW_p/a$)		1013			
	Lifetime of modules (a)		30	30	35	35
Costs[1]	System capital costs[3] (CHF/kW)	6 kW	3192 (2851-3635)	2591-2920	1679-2382	1572-2045
		10 kW	2895 (2619-3162)	2358-2657	1529-2168	1034-1475
		30 kW	2154 (1908-2326)	1747-1971	1132-1608	774-1107
		100 kW	1300 (1052-1548)	969-1148	591-940	534-814
		1000 kW	1106 (895-1318)	824-977	503-800	455-693
	Electricity generation costs[4] (Rp./kWh)	6 kW	26 (23-29)	21-24	13-18	13-16
		10 kW	23 (22-25)	20-22	12-17	9-12
		30 kW	18 (17-19)	15-17	10-13	7-9
		100 kW	12 (11-14)	10-11	6-9	6-7
		1000 kW	10 (8-11)	8-9	5-7	4-6
Life-cycle GHG emissions[1,5,6]	(g CO_2eq/ kWh)	multi-c Si	57 (39-69)	35-66	21-55	7-45
		single-c Si	91 (62-109)	56-104	33-88	11-71
		thin-film CdTe	37 (25-43)	23-42	15-36	8-30
		ribbon-Si	64 (43-76)	n.a.	n.a.	n.a.
		a-Si	60 (41-72)	n.a.	n.a.	n.a.
		thin-film CIS	51 (34-61)	n.a.	n.a.	n.a.

[1] All data provided here refer to building-attached or -integrated PV. Large open-ground PV installations have not been addressed since from the current perspective social and political constraints are likely in Switzerland.
[2] Assumed in this study based on the average yield for PV plants in Switzerland in (Vontobel et al. 2016) and used as reference value for cost & LCA calculations.
[3] Including PV module, balance of system, inverter, labor and other costs. Ranges provided for future costs reflect optimistic and pessimistic cost reduction rates, based on the current best estimates.
[4] Calculation includes system capital costs as well as costs for decommissioning, operation and maintenance (including replacement of inverter and balance of system during the lifetime). Ranges today are based on the

ranges of investment costs. Ranges provided for future costs reflect optimistic and pessimistic cost reduction rates, based on the current best estimates. Calculated with the current average, annual PV yield.

[5] Greenhouse gas emissions are used as key indicator for the environmental performance; further indicators can be found in the report. All indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of annual yields in Switzerland (850-1500 $kWh/kW_p/a$). For comparison: the current Swiss electricity consumption mix (incl. imports) has a GHG intensity of about 100 g $CO_{2eq.}$/kWh (low voltage).

[6] Current reference values are calculated with a yield of 1013 $kWh/kW_p/a$ (instead of 970 $kWh/kW_p/a$ in the previous evaluation). No estimates for future ribbon-Si, a-Si and thin-film CIS modules available. Ranges for emissions of future technologies reflect both variability of assumptions concerning future technology development and variability of site-dependent annual PV yields in Switzerland (850-1500 $kWh/kW_p/a$).

[7] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants to be built today with generation and cost data from the end of 2018.

[8] Generation in 2017 (swissolar 2018) – latest data available, not differentiating between roof-top and façade installations.

[9] Extrapolation based on the growth of PV during the last few years.

[10] Sustainable generation potential using to the current Swiss building stock according to (Remund 2017). This sustainable potential is supposed to correspond to "exploitable" potentials as quantified in this report and as discussed in (Bauer et al. 2017). Due to higher module efficiency, less area per installed capacity will be needed in the future. This effect is not taken into account here and therefore, depending on the time buildings will be equipped with PV modules, potential generation will increase by up to 20%. In addition to these potentials, detailed estimates for the technical roof-top generation potentials based on data from "sonnendach.ch" are available, which have been linked to generation costs (LCOE) resulting in cost-potential curves. These were calculated for all the roofs in Switzerland, as well as roofs with three different levels of solar irradiation. The corresponding LCOE curves are provided in section 10.3.

[11] This electricity generation range represents the technical potential for an LCOE range of 10-15 Rp./kWh (using cost data for year 2035) as a result of the cost vs. potential calculations, discussed and presented in section 10.3. To which extent this potential can be exploited is unknown.

[12] This is the latest estimate according to SFOE[23] based on the recently available data regarding available facades on existing buildings in Switzerland[24]. Electricity generation costs for this potential have not been quantified. To which extent this potential can be exploited is unknown.

[23] https://www.bfe.admin.ch/bfe/de/home/news-und-medien/medienmitteilungen/mm-test.msg-id-74641.html

[24] https://www.uvek-gis.admin.ch/BFE/sonnenfassade/

Data sheet – Natural gas combined cycle and CHP plants

Technology: Natural gas can be used in large Combined Cycle (NGCC) power plants as well as smaller, decentralized combined heat and power (CHP) generation units. Plant sizes range from 1 kW_{el} to the order of GW_{el}. "Carbon Capture, Utilization and Storage" (CCUS) for large natural gas power plants is currently a field of R&D. Technologies for CO_2 capture are mature; future development aims at increasing efficiencies and further reduction of combustion-related emissions of air pollutants.

Electricity from natural gas		New power plants			
		Current[4]	2020	2035	2050
Potential	TWh/a	1.6	n.a.[5]		
Electricity generation costs[1] (with heat credits for CHP) (Rp./kWh_{el})	NGCC	9.7 (9.2 - 10.6)	9.6 (9.1 - 10.5)	11.1 (10.6 – 11.8)	12.6 (12.0 - 13.4)
	NGCC post	11.4 (10.3 - 13.1)	11.3 (10.3 - 12.9)	12.5 (11.5 - 13.9)	13.7 (12.7 - 15.1)
	NGCC pre	11.5 (10.6 - 13.2)	11.2 (10.3 - 12.8)	12.3 (11.5 - 13.8)	13.4 (12.6 - 14.9)
	CHP 1kW_{el}	71.7 (50.0 - 114.3)	70.3 (49.2 - 111.9)	67.2 (47.5 - 106.2)	66.0 (47.2 - 103.7)
	CHP 10kW_{el}	29.4 (22.0 - 45.0)	29.2 (21.8 - 45.2)	29.6 (22.7 - 45.0)	30.5 (23.8 - 45.8)
	CHP 100kW_{el}	20.0 (14.6 - 25.6)	20.1 (14.1 - 26.3)	21.8 (15.5 - 28.0)	23.6 (16.9 - 29.9)
	CHP 1000kW_{el}	15.6 (13.2 - 18.3)	15.7 (13.2 - 18.8)	17.3 (14.8 - 20.4)	19.1 (16.4 - 22.3)
Electricity generation costs[1] (without heat credits) (Rp./kWh_{el})	CHP 1kW_{el}	93.5 (72.0 - 130.8)	91.4 (71.4 - 128.6)	90.7 (72.3 - 124.8)	91.7 (74.2 - 124.0)
	CHP 10kW_{el}	48.2 (39.7 - 62.2)	48.1 (39.8 - 62.3)	50.7 (42.7 - 64.1)	53.5 (45.6 - 66.7)
	CHP 100kW_{el}	29.6 (26.1 - 34.4)	29.7 (26.3 - 34.4)	32.2 (28.7 - 36.8)	34.9 (31.3 - 39.5)
	CHP 1000kW_{el}	20.8 (19.0 - 23.1)	20.9 (19.1 - 23.1)	22.7 (20.9 - 25.0)	25.0 (23.1 - 27.3)
Fuel costs: natural gas (CHF/MWh)	See Table 11.2				
Life cycle GHG emissions[2,3] (gCO_2-eq/kWh_{el})	NGCC	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	NGCC post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
	NGCC pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	CHP 1kW_{el}	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
	CHP 10kW_{el}	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	CHP 100kW_{el}	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	CHP 1000kW_{el}	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)

[1] Calculations include capital, decommissioning, operation & maintenance costs as well as costs associated with direct CO_2 emissions for NGCC plants. Ranges reflect optimistic and pessimistic technology specification and development, respectively, as well as future cost reduction rates.

[2] GHG emissions are used as key indicator for environmental performance; further indicators can be found in (Bauer et al. 2017). Indicators are quantified using Life Cycle Assessment (LCA) methodology and thus represent the complete fuel cycle/energy chain. Ranges reflect optimistic and pessimistic technology specification and development. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 90 $_g$ $CO_{2eq.}$/kWh (high voltage).

[3] GHG emissions of CHP units are calculated applying exergy allocation for combined heat and power generation.

[4] "Current" refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new power plants in 2018.

[5] Electricity generation (and import) is technically only limited by fuel/electricity import capacities; however, limited by economic, environmental and social constraints in reality. A thorough analysis of CHP potentials has not been performed, since such units are currently not economically viable options and space heating demand will considerably change in the coming years.

NGCC	Natural gas combined cycle
NGCC post	Natural gas combined cycle, CO_2 capture post-combustion
NGCC pre	Natural gas combined cycle, CO_2 capture pre-combustion
CHP 1kW_{el}	Natural gas piston engine combined heat and power plant 1 kW_{el}
CHP 10kW_{el}	Natural gas piston engine combined heat and power plant 10 kW_{el}
CHP 100kW_{el}	Natural gas piston engine combined heat and power plant 100 kW_{el}
CHP 1000kW_{el}	Natural gas piston engine combined heat and power plant 1000 kW_{el}

Data sheet – Fuel cells

Technology: Fuel cells electrochemically convert natural gas into heat and electricity. Systems operating on hydrogen are assumed to be equipped with a fuel reformer to generate hydrogen on site. Installations are extremely scalable from <1 kW to hundreds of kilowatts. Operation is very flexible, with high part load efficiency; start up times range from minutes to hours, depending on fuel cell type.

Some fuel cell types have been made commercially available, though most projects are still dependent on funding support for demonstration projects. Significant improvements to capital costs, system lifetimes and efficiencies are expected for the future.

Fuel cells			**New power plants: current[1]**	**2020**	**2035**	**2050**
Potential[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Electricity generation costs[3,4] (with heat credits)	Rp./kWh	PEFC 1 kW_{el}	79 (49 - 104)	33 - 92	23 - 48	21 - 46
		SOFC 1 kW_{el}	81 (57 - 109)	35 - 99	23 - 48	20 - 45
		SOFC 300 kW_{el}	42 (29 - 63)	24 - 57	16 - 39	16 - 25
		MCFC 300 kW_{el}	25 (19 - 34)	17 - 32	17 - 32	16 - 26
		PAFC 300 kW_{el}	25 (19 - 35)	16 - 31	15 - 24	15 - 23
Fuel costs: natural gas and biomathane[9]	CHF/MWh	See Table 11.2				
GHG emissions[5,6,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	730 (620 - 850)	550 - 730	490 - 610	450 - 560
		SOFC 1 kW_{el}	560 (500 - 770)	490 - 650	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
GHG emissions[5,7,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	390 (350 - 430)	310 - 410	300 - 380	300 - 370
		SOFC 1 kW_{el}	410 (350 - 520)	320 - 480	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] Refers to the most up-to-date information and represents modern technology on the market; current electricity generation costs refer to new fuel cells to be built today (reference year 2018).
[2] Potential is technically unlimited; this estimation is based on replacement of fossil fueled domestic heating.
[3] Generation costs include investment, operation and maintenance and fossil natural gas as fuel. Ranges provided here represent variability in assumptions concerning e.g. efficiency, investment cost, lifetime, etc. Details concerning data used and sensitivities can be found in section 0. Since the main purpose of stationary fuel cells in Switzerland would be heat supply, only electricity generation costs with heat credits are provided in this fact sheet.
[4] Results shown for fossil natural gas as a fuel source. If biomethane is used, costs increase by 8-14 Rp./kWh.
[5] GHG emissions are used as key indicator for the environmental performance of technologies; further indicators can be found in (Bauer et al. 2017). All indicators are quantified using Life Cycle Assessment (LCA) methodology and represent the complete fuel cycle/energy chain. The ranges provided here reflect potential variability of performance parameters such as efficiency and lifetime. For comparison: the current Swiss electricity consumption mix (including imports) has a GHG intensity of about 100 g $CO_{2eq.}$/kWh (low voltage). Since only rounded numbers are provided here, small changes in LCOE (in red) due to slightly changed efficiencies for some technologies are not reflected in changes in GHG emissions.
[6] Emissions allocated between heat & electricity based on exergy. Results shown for electricity production.
[7] GHG emissions based on system expansion, which means that the GHG emissions associated with the equivalent heat produced by a modern condensing natural gas boiler have been subtracted from the total.
[8] GHG emissions with biomethane as fuel decrease by 32-34%.
[9] According to section 11.1: natural gas prices for Swiss residential and industry, respectively, and a premium of 75 CHF/MWh for biomethane.

6 Datenblätter

Die folgenden Datenblätter enthalten die wichtigsten Zahlen für jene Technologien, für die Aktualisierungen der Stromproduktionskosten im Vergleich zu (Bauer et al. 2017) vorgenommen wurden: Wasserkraft, Windkraftwerke, Fotovoltaikanlagen, Erdgaskraftwerke und Erdgas-Blockheizkraftwerke sowie Brennstoffzellen. Stromproduktionspotenziale wurden lediglich für PV-Anlagen und Wasserkraft aktualisiert. Aktualisierte Zahlen in den Tabellen der Faktenblätter sind in rot hervorgehoben.

Datenblatt – Grosse Wasserkraftwerke

Technologie: Wasserkraftwerke erzeugen Strom durch die Umwandlung der im Wasser enthaltenen potenziellen oder kinetischen Energie in Elektrizität. Kraftwerke mit Leistungen von mehr als 10 MW mittlerer, mechanischer Bruttoleistung gelten in der Schweiz als „gross“ und werden in folgende Kategorien eingeteilt:

- Speicherkraftwerke: Wasser wird mit einem Damm in einem Speichersee aufgestaut, über eine Druckleitung auf eine Turbine geleitet und dort turbiniert.
- Laufkraftwerke: das Wasser fliesst direkt vom Fluss auf eine Turbine oder wird mit einem Damm gestaut und über einen Ausleitkanal oder eine Druckleitung auf eine Turbine weiter flussabwärts geleitet (Ausleitkraftwerk).
- Pumpspeicherkraftwerke: erzeugen Strom zu Spitzenlastzeiten, indem Wasser zwischen Speicherseen auf verschiedenen Höhen gepumpt und turbiniert wird.

Grosse Wasserkraftwerke sind eine “fertig entwickelte” Technologie. Wirkungsgrade von Turbinen werden sich in Zukunft nur geringfügig steigern lassen.

Grosse Wasserkraftwerke			Neuanlagen: heute[1]	2020	2035	2050
Potenzial[2] (Mittlere, erneuerbare Produktionserwartung)	TWh/a		31.9[10]	~32.0	33.6-34.8	33.6-34.8[11]
					32.5-34.2	32.5-33.6[11]
Investitionskosten[3]	CHF/kW		3’500 (2’000-10’000)	2’000-10’000	2’000-10’000	2’000-10’000
Stromproduktions-kosten[4,5]	Rp./kWh	Laufkraftwerk[8]	7-30	7-30	7-30	7-30
		Speicherkraftwerk[9]				
Treibhausgas-emissionen[6,7]	g CO_2eq./kWh	Laufkraftwerk	5-10	~5-10	~5-10	~5-10
		Speicherkraftwerk	5-15	~5-15	~5-15	~5-15

[1] “Heute” bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke; das heutige Potenzial entspricht der mittleren, erneuerbaren Produktionserwartung Ende 2018 (Produktionserwartung abzüglich Verbrauch der Zubringerpumpen; die tatsächliche Produktion hängt ab vom Niederschlag, vom Klima, etc.).

[2] Nach (SFOE 2019). Der zukünftige Ausbau der Wasserkraft wird hauptsächlich von den wirtschaftlichen Rahmenbedingungen abhängen sowie von der Akzeptanz neuer Kraftwerke. Für den Ausbau der Schweizer Grosswasserkraft stehen bis 2030 rund 700 Millionen Franken Investitionsbeiträge zur Verfügung. Neubauten bzw. die Erweiterung bestehender Kraftwerke können etwa gleich viel zu einer gesteigerten Produktion beitragen. Die obere Zeile für 2035 und 2050 enthält die mögliche Produktion ohne Berücksichtigung neuer gesetzlicher Vorgaben (“Gewässerschutzgesetz”); in der unteren Zeile wird eine Reduktion der Produktion durch das Gewässerschutzgesetz von 1’170 GWh/a berücksichtigt (Reduktion insgesamt: 1’300 GWh/a; 90% werden der Grosswasserkraft angerechnet, 10% der Kleinwasserkraft – proportional zur heutigen Produktion).

[3] Die verfügbaren Daten erlauben keine Unterscheidung zwischen Lauf- und Speicherkraftwerken. 3’500 CHF/kW repräsentiert einen gewichteten Durchschnitt für Investitionen zur zusätzlichen Stromproduktion (in neue Anlagen und in die Erweiterung bestehender Anlagen) ohne Berücksichtigung von Bauten zur hauptsächlichen Regulierung der Schwall- und Sunkproblematik.

[4] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Die Bandbreiten reflektieren standortspezifische Faktoren.

[5] Unter der Annahme, dass wirtschaftlich attraktive Standorte zuerst genutzt werden, tendieren die Stromproduktionskosten neuer Anlagen in Zukunft vom unteren Ende des Bereichs ans obere Ende zu steigen. Insgesamt können zusätzlich rund 1.6 TWh/a zu Produktionskosten von weniger als 15 Rp./kWh erzeugt werden (ohne Berücksichtigung des Gewässerschutzgesetzes).

[6] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g CO_2-eq./kWh auf (Hochspannung).

[7] Es wird angenommen, dass die Umweltauswirkungen neuer Kraftwerke in etwa jenen der heutigen entsprechen.
[8] LCOE der heute bestehenden Kraftwerke mit tlws. amortisiertem Kapital: 5-6 (2-10) Rp./kWh.
[9] LCOE der heute bestehenden Kraftwerke mit tlws. amortisiertem Kapital: 6 (3-9) Rp./kWh.
[10] 35.9 TWh/a mittlere, erneuerbare Produktionserwartung aus Wasserkraftwerken per 1.1.2019 abzüglich einer Produktion von 4 TWh/a in Kleinwasserkraftwerken (KWK) gemäss Statistik KWK von Swiss Small Hydro.
[11] Mit fortschreitendem Klimawandel werden die Gletscher schrumpfen und Gletscherseen bilden, die für die Wasserkraft genutzt werden könnten. Das BFE (SFOE 2019) schätzt dieses zusätzliche Potenzial auf rund 700 GWh/a; ob und inwieweit dieses Erzeugungspotenzial realisiert werden kann, ist jedoch sehr unsicher und daher nicht in diesen Zahlen berücksichtigt.

Datenblatt – Kleinwasserkraft

Technologie: Wasserkraftwerke erzeugen Strom durch die Umwandlung der im Wasser enthaltenen potenziellen oder kinetischen Energie in Elektrizität. Kraftwerke mit Leistungen von weniger als 10 MW fallen in der Schweiz in die Kategorie „Kleinwasserkraft“. Kleinwasserkraftwerke können auch in bestehende Infrastruktur, etwa Trinkwasserleitungen, integriert werden. Unterschieden werden je nach Art der Nutzung des Wassers:

- Speicherkraftwerke: Wasser wird mit einem Damm in einem Speichersee aufgestaut
- Laufkraftwerke: besitzen keinen Damm; das hydrologische Regime wird nicht oder kaum verändert

Konventionelle Kleinwasserkraftwerke sind im allgemeinen eine “fertig entwickelte” Technologie. Wirkungsgrade von Turbinen werden in Zukunft nur geringfügig steigen. Aktuelle Forschung zielt jedoch darauf ab, Kleinwasserkraftwerke mit geringen Abflüssen und geringen nutzbaren Höhendifferenzen effizienter zu machen, um zusätzliche Standorte nutzen zu können.

Kleinwasserkraftwerke		**Neuanlagen: heute[1]**		**2020**	**2035**	**2050**
Potenzial[2]	TWh/a		4.0	4.0	~4.0-4.4	~4.0-4.4
Investitions-kosten[3]	CHF/kW	Ausleitungs-/ Laufwasserkraftwerke	6’160 (5’200-13’700)	~6’160	~7’150	~7’400
		Trinkwasser-kraftwerke	11’150 (9’600-25’100)	~11’150	~13’000	~13’400
Stromproduktions-kosten[4,5]	Rp./kWh	Ausleitungs-/ Laufwasserkraftwerke	12-28	~12-28	~14-33	~14-34
		Trinkwasserkraftwerke	17-42	~17-42	~20-49	~20-50
Treibhausgas-emissionen[6,7]	g CO_2eq./kWh	Ausleitungs-/ Laufwasserkraftwerke	~5-10	~5-10	~5-10	~5-10
		Trinkwasserkraftwerke	~2-5	~2-5	~2-5	~2-5

[1] “Heute” bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke; das heutige Potenzial entspricht der mittleren, erneuerbaren Produktionserwartung Ende 2018 (die tatsächliche Produktion hängt ab vom Niederschlag, vom Klima, etc.).

[2] Die Bandbreiten der zukünftigen Potenziale reflektieren die Schätzungen einiger aktueller Studien (SFOE 2019). Das BFE geht von einem zusätzlichen Potenzial von 110-550 GWh/a aus. Es wird davon ausgegangen, dass diese Zahlen um rund ~130 GWh/a reduziert werden müssen, als Resultat des Gewässerschutzgesetzes. Die tatsächliche Ausweitung der Produktion mit Kleinwasserkraftwerken wird von finanziellen Unterstützungsmassnahmen abhängen.

[3] Heutige Investitionskosten wurden anhand der “KEV-Liste” (kostendeckende Einspeisevergütung) abgeschätzt. Das ausgewertete Sample umfasst Projekte für 1049 neue Kleinwasserkraftwerke. Zukünftige Investitionskosten werden tendenziell zunehmen, da zuerst an vorteilhaften Standorten gebaut wird und Regulierungen im Umweltbereich eher zunehmen werden.

[4] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Die Bandbreiten reflektieren standortspezifische Faktoren.

[5] Unter der Annahme, dass günstige Standorte zuerst genutzt werden, werden die Kosten von 2020 bis 2050 vom unteren Ende der angegebenen Bandbreite bis zum oberen Ende zunehmen.

[6] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g CO_2-eq./kWh auf (Niederspannung).

[7] Es wird angenommen, dass die Umweltauswirkungen neuer Kraftwerke in etwa jenen der heutigen entsprechen, da sie vergleichsweise gering sind und sich die Technologie nicht substanziell entwickeln wird.

Datenblatt – Windkraftwerke

Technologie: Windturbinen mit horizontalen Achsen dominieren den heutigen Markt. Strom wird mittels Rotorblättern durch die Umwandlung der kinetischen Energie des Luftstroms in Elektrizität erzeugt. Heutige Turbinen können bei Windgeschwindigkeiten von 3-34 m/s Strom erzeugen.

Windkraftwerke			Neuanlagen: heute[10]	2020	2035	2050
Leistung		Onshore	1-3 MW (70% der installierten Leistung) Neue Turbinen: 2-4 MW	Grösste Turbine heute: 8 MW (on-/offshore), 164 m Rotordurchmesser, 220 m Nabenhöhe Machbarkeit von 20 MW Turbinen wurde demonstriert.		
		Offshore	>3 MW			
Kapazitäts-faktor (cf)[1]		Allgemein	0.1-0.55 Weltdurchschnitt ~0.23 (2013)	Kapazitätsfaktoren werden etwas zunehmen durch Verbesserungen der Turbinen und durch genauere Vorhersagen der Windgeschwindigkeiten zur optimalen Standortwahl.		
		Onshore	CH: 0.21; DE: 0.22 (2015)			
		Offshore	Bis zu 0.55			
Potenzial[11]	TWh/a	Schweiz	0.1	0.1 - 0.6	0.7 - 1.7	1.4 - 4.3
	TWh/a	Europa[6]	~260	580-630	2030: 604-988	No data available
Strom-produktions-kosten[2,3,11]	Rp./kWh	Schweiz	15 - 20	15 - 20	10 - 15	9 - 13
		Europa, onshore	4 - 15	4 - 15	3 - 11	3 - 10
		Europa, offshore[7]	9 - 16	9 - 16	5 - 12	5 - 12
Treibhausgas-emissionen[2,4,5]	g CO_2-eq./kWh	Schweiz	~15 (8 - 27)	5 - 30	5 - 30	5 - 30
		Europa, onshore[8]	8 - 21	5 - 25	5 - 25	5 - 25
		Europa, offshore[9]	8 - 16	5 - 20	5 - 20	5 - 20

[1] Jährliche "Volllaststunden" dividiert durch 8760 h/a. Jährliche Volllaststunden entsprechen der Zeit, die sich aus der Jahresproduktion bei Nennleistung ergibt.

[2] Stromproduktionskosten beinhalten Investitionskosten, Betriebs- und Wartungs- sowie andere Kosten. Der Jahresertrag ist der wichtigste Einflussfaktor auf Stromproduktionskosten und Ökobilanzergebnisse; die angegebenen Bandbreiten hier repräsentieren typische Erträge in der Schweiz bzw. Europa. An Standorten mit sehr guten oder sehr schlechten Windbedingungen können Kosten und THG-Emissionen ausserhalb der angegebenen Bandbreiten liegen.

[3] Zukünftige Kosten sind grobe Schätzungen basierend auf Literatur und den aktuellen Trends.

[4] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren und Leistungsklassen der Turbinen. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g $CO_{2eq.}$/kWh auf (Hochspannung).

[5] Es wird nicht erwartet, dass sich die Umweltauswirkungen in Zukunft stark verändern. Eine Abnahme würde aus der besseren Nutzung des Windes resultieren; eine Zunahme aus der Verschlechterung der verfügbaren Standorte.

[6] Keine Unterscheidung zwischen onshore- und offshore-Turbinen möglich.

[7] Bandbreiten geschätzt nach Literaturdaten für Europa in Figure 9.5; 1.15 CHF/€.

[8] Bei Kapazitätsfaktoren von 0.15-0.35.

[9] Basierend auf der ecoinvent Datenbank, v3.3, "allocation – cut-off by classification" bei cf von 0.30-0.55.

[10] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute (2018 oder auch 2020) (theoretisch) neu gebaute Kraftwerke – da Planung und Lizensierungsverfahren für solche Windprojekte in der Schweiz allerdings schon vor Jahren hätten beginnen müssen, würden heute errichtete Windkraftwerke nicht von Kostenvorteilen der letzten Jahre profitieren können; diese werden für Anlagen in der Schweiz erst ab etwa dem Jahr 2030 relevant.

[11] Nach (suisseéole 2019b), werden die Windgeschwindigkeiten im "Windatlas" (www.windatlas.ch – Basis für das Windkonzept Schweiz), teilweise massiv unterschätzt. Folglich könnten das Potenzial und die Stromproduktionskosten hier unter- bzw. überschätzt sein.

Datenblatt – Fotovoltaik

Technologie: Fotovoltaikzellen wandeln Sonnenstrahlung direkt in Strom um. In der Schweiz sind auf Dächern installierte Anlagen üblich. PV-Anlagen können folgendermassen kategorisiert werden:

1. Generation: kristalline Siliziumzellen (monokristallines Si und polykristallines Si); heute dominierend

2. Generation: Dünnschichtzellen – CdTe, amorphes Si, CIGS; heute bereits am Markt

3. Generation: konzentrierende Zellen, organische Zellen; in Entwicklung

Die aktuelle Technologieentwicklung zielt vor allem auf erhöhte Wirkungsgrade und sinkende Produktionskosten ab.

Fotovoltaik			Neue Anlagen			
			Heute[7]	2020	2035	2050
Potenzial	Dachanlagen	TWh/a	1.68[8]	2.7[9]	24.6[10] (22-54)[11]	
	Fassadenanlagen	TWh/a			5.6[10] 17[12]	
Technische Parameter[1]	Sonneneinstrahlung ($kWh/m^2/a$)		Schweiz, Durchschnitt der Anlagen heute: 1267			
	Wirkungsgrade	Modul (%)	17	17-19	20-27	24-27
		Inverter (%)	98			
	Fläche pro kW_p installierter Leistung (m^2/kW_p)		6	5.4-6.2	3.8-5.0	3.8-5.0
	Performance ratio (%)		80			
	Durchschnittlicher Ertrag Schweiz[2] ($kWh/kW_p/a$)		1013			
	Lebensdauer der Module (a)		30	30	35	35
Kosten[1]	System Kapitalkosten[3] (CHF/kW)	6 kW	3192 (2851-3635)	2591-2920	1679-2382	1572-2045
		10 kW	2895 (2619-3162)	2358-2657	1529-2168	1034-1475
		30 kW	2154 (1908-2326)	1747-1971	1132-1608	774-1107
		100 kW	1300 (1052-1548)	969-1148	591-940	534-814
		1000 kW	1106 (895-1318)	824-977	503-800	455-693
	Stromproduktionskosten[4] (Rp./kWh)	6 kW	26 (23-29)	21-24	13-18	13-16
		10 kW	23 (22-25)	20-22	12-17	9-12
		30 kW	18 (17-19)	15-17	10-13	7-9
		100 kW	12 (11-14)	10-11	6-9	6-7
		1000 kW	10 (8-11)	8-9	5-7	4-6
Treibhausgas-emissionen[1,5,6]	(g CO_2eq/ kWh)	multi-kristallines Si	57 (39-69)	35-66	21-55	7-45
		mono-kristallines Si	91 (62-109)	56-104	33-88	11-71
		Dünnschicht CdTe	37 (25-43)	23-42	15-36	8-30
		Ribbon-Si	64 (43-76)	n.a.	n.a.	n.a.
		Amorphes Si	60 (41-72)	n.a.	n.a.	n.a.
		Dünnschicht CIS	51 (34-61)	n.a.	n.a.	n.a.

[1] Alle Angaben hier beziehen sich auf PV-Anlagen auf bestehenden Gebäuden. Freiflächenanlagen werden nicht untersucht, da deren Akzeptanz aus heutiger Sicht in der Schweiz als nicht gegeben angesehen wird.
[2] Entspricht dem Durchschnitt der installierten Anlagen heute nach (Vontobel et al. 2016); wird hier als Referenzwert für Kostenrechnungen und Ökobilanzen verwendet.
[3] Inkl. PV-Modul, Inverter, weiteren Bauteilen, Arbeits- und anderen Kosten. Bandbreiten für zukünftige Kosten reflektieren optimistische und pessimistische Einschätzung der Entwicklung, basierend auf den heutigen Mittelwerten.

[4] Beinhaltet Kosten für Investitionen und Entsorgung, Betrieb und Wartung (inkl. Ersatz des Inverters und BOS während der System-Lebensdauer). Die Bandbreiten für 2018 ergeben sich aus der Variation der heutigen Investitionskosten. Zukünftige Kosten beinhalten je ein Szenario mit optimistischer und pessimistischer Einschätzung der Entwicklung, ausgehend von den heutigen Mittelwerten. Berechnet mit dem heutigen Durchschnittsertrag.
[5] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren standortspezifische Einflussfaktoren. Die angegebenen Bandbreiten ergeben sich aus der Variation der Jahreserträge (850-1500 kWh/kW_p/a). Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g $CO_{2eq.}$/kWh auf (Niederspannung).
[6] Heutige Referenzwerte werden mit einem Ertrag von 1013 kWh/kW_p/a berechnet (in der vorangegangenen Studie: 970 kWh/kW_p/a). Zahlen für zukünftige ribbon-Si, a-Si und CIS Zellen sind nicht verfügbar. Die Bandbreiten für zukünftige Technologien reflektieren Unsicherheiten in der zukünftigen Technologieentwicklung und Variabilität der Jahreserträge (850-1500 kWh/kW/a).
[7] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie auf dem Markt; Stromproduktionskosten beziehen sich auf heute neu gebaute Kraftwerke mit Kostendaten von Ende 2018.
[8] Stromproduktion mit PV-Anlagen im Jahr 2017 (swissolar 2018) – neueste verfügbare Daten ohne Unterscheidung zwischen Dach- und Fassadenanlagen.
[9] Extrapolation basierend auf der Zunahme der PV-Stromproduktion der letzten Jahre.
[10] Nachhaltiges Potenzial unter Ausnutzung des Schweizer Gebäudebestands nach (Remund 2017). Dieses nachhaltige Potenzial sollte den "ausschöpfbaren" Potenzialen entsprechen, welche generell in diesem Bericht angegeben sind und in (Bauer et al. 2017) diskutiert werden. Dank steigender Modulwirkungsgrade wird in Zukunft weniger Fläche pro PV-Leistung gebraucht. Dieser Effekt ist in den vorhandenen Potenzialschätzungen nicht berücksichtigt; abhängig davon, wann Gebäude mit PV-Anlagen ausgestattet werden, könnte das Potenzial dementsprechend um bis zu 20% höher liegen. Ergänzend zu diesen nachhaltigen Potenzialen sind detaillierte Angaben zu technischen Potenzialen über sonnendach.ch verfügbar, welche mit Stromgestehungskosten verknüpft wurden. Somit konnten Kosten-Potenzialkurven berechnet werden – für alle Dächer sowie für drei verschiedene Einstrahlungskategorien. Details dazu sind in Kapitel 10.3 zu finden.
[11] Diese Bandbreite der Stromproduktion stellt das technische Potenzial für Stromgestehungskosten von 10-15 Rp./kWh (unter Verwendung von Kostendaten für das Jahr 2035) dar, das sich aus den in Kapitel 10.3 beschriebenen und dargestellten Kosten- und Potenzialberechnungen ergibt. Inwieweit dieses Potenzial genutzt werden kann, ist unbekannt.
[12] Dies ist die neueste Schätzung des BFE[25] auf der Grundlage der aktuell verfügbaren Daten über verfügbare Fassaden an bestehenden Gebäuden in der Schweiz[26]. Die Stromerzeugungskosten für dieses Potenzial wurden nicht quantifiziert. Inwieweit dieses Potenzial genutzt werden kann, ist unbekannt.

[25] https://www.bfe.admin.ch/bfe/de/home/news-und-medien/medienmitteilungen/mm-test.msg-id-74641.html
[26] https://www.uvek-gis.admin.ch/BFE/sonnenfassade/

Datenblatt – Strom aus Erdgaskraftwerken und BHKW

Technologie: Erdgas kann in grossen Gas- und Dampfkraftwerken (GuD) und kleinen, dezentralen Blockheizkraftwerken (BHKW) zur Stromproduktion genutzt werden. Die Leistungen der Anlagen liegen in einem breiten Bereich von 1 kW_{el} bis zu einigen hundert MW_{el}. Die Abscheidung, Nutzung und/oder geologische Speicherung von CO_2 ("Carbon Capture, (Utilization) and Storage" (CCUS)) bei grossen Gaskraftwerken befindet sich heute im Versuchs- und Forschungsstadium. Die Kraftwerkstechnologien sind in einem fortgeschrittenen Entwicklungsstadium; zukünftige Entwicklungen zielen darauf ab, Wirkungsgrade zu erhöhen und Schadstoffemissionen zu senken.

Strom aus Erdgas		**Neue Kraftwerke**			
		Heute[4]	**2020**	**2035**	**2050**
Potenzial	TWh/a	1.6	n.a.[5]		
Stromproduktionskosten[1]	GuD	9.7 (9.2 - 10.6)	9.6 (9.1 - 10.5)	11.1 (10.6 – 11.8)	12.6 (12.0 - 13.4)
	GuD post	11.4 (10.3 - 13.1)	11.3 (10.3 - 12.9)	12.5 (11.5 - 13.9)	13.7 (12.7 - 15.1)
(mit Wärmegutschriften für BHKW)	GuD pre	11.5 (10.6 - 13.2)	11.2 (10.3 - 12.8)	12.3 (11.5 - 13.8)	13.4 (12.6 - 14.9)
	BHKW $1kW_{el}$	71.7 (50.0 - 114.3)	70.3 (49.2 - 111.9)	67.2 (47.5 - 106.2)	66.0 (47.2 - 103.7)
	BHKW $10kW_{el}$	29.4 (22.0 - 45.0)	29.2 (21.8 - 45.2)	29.6 (22.7 - 45.0)	30.5 (23.8 - 45.8)
	BHKW $100kW_{el}$	20.0 (14.6 - 25.6)	20.1 (14.1 - 26.3)	21.8 (15.5 - 28.0)	23.6 (16.9 - 29.9)
(Rp./kWh_{el})	BHKW $1000kW_{el}$	15.6 (13.2 - 18.3)	15.7 (13.2 - 18.8)	17.3 (14.8 - 20.4)	19.1 (16.4 - 22.3)
Stromproduktionskosten [1]	BHKW $1kW_{el}$	93.5 (72.0 - 130.8)	91.4 (71.4 - 128.6)	90.7 (72.3 - 124.8)	91.7 (74.2 - 124.0)
(ohne Wärmegutschriften)	BHKW $10kW_{el}$	48.2 (39.7 - 62.2)	48.1 (39.8 - 62.3)	50.7 (42.7 - 64.1)	53.5 (45.6 - 66.7)
(Rp./kWh_{el})	BHKW $100kW_{el}$	29.6 (26.1 - 34.4)	29.7 (26.3 - 34.4)	32.2 (28.7 - 36.8)	34.9 (31.3 - 39.5)
	BHKW $1000kW_{el}$	20.8 (19.0 - 23.1)	20.9 (19.1 - 23.1)	22.7 (20.9 - 25.0)	25.0 (23.1 - 27.3)
Brennstoffkosten: Erdgas (CHF/MWh)	siehe Table 11.2				
	GuD	393 (387 - 400)	380 (374 - 386)	365 (359 - 371)	357 (346 - 363)
	GuD post	104 (94 - 114)	99 (90 - 109)	90 (81 - 103)	83 (75 - 100)
THG-Emissionen[2,3]	GuD pre	97 (81 - 120)	91 (76 - 112)	86 (72 - 107)	83 (70 - 103)
	BHKW $1kW_{el}$	643 (611 - 677)	636 (605 - 670)	618 (589 - 648)	606 (578 - 635)
(gCO_{2eq}/kWh_{el})	BHKW $10kW_{el}$	611 (583 - 633)	605 (575 - 632)	586 (558 - 613)	575 (546 - 601)
	BHKW $100kW_{el}$	506 (476 - 529)	500 (464 - 530)	482 (448 - 511)	474 (441 - 503)
	BHKW $1000kW_{el}$	481 (459 - 500)	473 (450 - 498)	452 (429 - 476)	445 (423 - 468)

[1] Berücksichtigt werden Kosten für Investitionen, Brennstoff, Entsorgung, Wartung und Betrieb sowie für direkte CO_2-Emissionen bei GuD-Kraftwerken. Die Bandbreiten reflektieren optimistische bzw. pessimistische Technologiespezifizierung und -entwicklung sowie die entsprechenden Veränderungen der Kosten.

[2] THG-Emissionen werden hier als Hauptindikator für Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die Bandbreiten reflektieren Unterschiede in Kraftwerksparametern und der zukünftigen Entwicklung. Zum Vergleich: Der heutige CH-Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 90 g $CO_{2eq.}$/kWh auf.

[3] Bei BHKW werden Emissionen anhand des Exergiegehalts von Strom und Wärme aufgeteilt.

[4] "Heute" bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie; Stromproduktionskosten beziehen sich auf heute (Referenzjahr 2018) neu gebaute Anlagen.

[5] Stromproduktion bzw. Importe sind technisch vor allem von Erdgas- bzw. Stromimportkapazitäten limitiert; in der Praxis spielen vor allem wirtschaftliche, ökologische und gesellschaftliche Faktoren eine Rolle. Eine vertiefte Analyse zu BHKW-Potenzialen wurde nicht vorgenommen, da die Wirtschaftlichkeit derzeit nicht gegeben ist und sich der Bedarf an Raumwärme in den nächsten Jahrzehnten stark verändern wird.

NGCC – GuD	Natural gas combined cycle – Gas- & Dampfkraftwerk
GuD post	GuD-Kraftwerk mit CO_2-Abscheidung "post-combustion"
GuD pre	GuD-Kraftwerk mit CO_2-Abscheidung „pre-combustion"
BHKW $1kW_{el}$	Erdgas-Blockheizkraftwerk mit Kolbenmotor 1 kW_{el}
BHKW $10kW_{el}$	Erdgas-Blockheizkraftwerk mit Kolbenmotor 10 kW_{el}
BHKW $100kW_{el}$	Erdgas-Blockheizkraftwerk mit Kolbenmotor 100 kW_{el}
BHKW $1000kW_{el}$	Erdgas-Blockheizkraftwerk mit Kolbenmotor 1000 kW_{el}

Datenenblatt – Strom aus Brennstoffzellen

Technologie: Die hier untersuchten Brennstoffzellen erzeugen elektrochemisch aus Methan (Erdgas oder Biogas) Strom und Wärme. Systeme, die mit Wasserstoff als Brennstoff funktionieren, sind mit einem Reformer ausgestattet, um vor Ort aus Erdgas Wasserstoff zu erzeugen. Die Leistungen von Brennstoffzellensysteme können stark variieren, von weniger als 1 kW_{el} bis zu Hunderten von kW_{el}. Im Betrieb sind Brennstoffzellen sehr flexibel und weisen hohe Wirkungsgrade unter Teillast auf; je nach Brennstoffzellentyp liegen die Anfahrzeiten im Bereich von Minuten bis Stunden.

Brennstoffzellen sind am Markt erhältlich. Die meisten Anlagen sind aber auf Unterstützungsmassnahmen im Rahmen von Demonstrationsprojekten angewiesen. Es wird davon ausgegangen, dass zukünftig Investitionskosten sinken, Lebensdauern und Wirkungsgrade substanziell zunehmen werden.

Brennstoffzellen			**Neue Anlagen: heute**[1]	**2020**	**2035**	**2050**
Potenzial[2]	TWh/a		<0.01	~1.2	~6.1	~7.9
Stromproduktionskosten[3,4] (mit Wärmegutschriften)	Rp./kWh	PEFC 1 kW_{el}	79 (49 - 104)	33 - 92	23 - 48	21 - 46
		SOFC 1 kW_{el}	81 (57 - 109)	35 - 99	23 - 48	20 - 45
		SOFC 300 kW_{el}	42 (29 - 63)	24 - 57	16 - 39	16 - 25
		MCFC 300 kW_{el}	25 (19 - 34)	17 - 32	17 - 32	16 - 26
		PAFC 300 kW_{el}	25 (19 - 35)	16 - 31	15 - 24	15 - 23
Brennstoffkosten: Erdgas und Biomethan[9]	CHF/MWh	siehe Table 11.2				
Treibhausgasemissionen[5,6,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	730 (620 - 850)	550 - 730	490 - 610	450 - 560
		SOFC 1 kW_{el}	560 (500 - 770)	490 - 650	480 - 560	440 - 520
		SOFC 300 kW_{el}	490 (360 - 540)	340 - 500	350 - 440	340 - 420
		MCFC 300 kW_{el}	560 (370 - 610)	360 - 580	380 - 490	360 - 450
		PAFC 300 kW_{el}	590 (500 - 650)	480 - 620	460 - 580	440 - 550
Treibhausgasemissionen[5,7,8]	g CO_2-eq./ kWh	PEFC 1 kW_{el}	390 (350 - 430)	310 - 410	300 - 380	300 - 370
		SOFC 1 kW_{el}	410 (350 - 520)	320 - 480	310 - 420	300 - 390
		SOFC 300 kW_{el}	390 (330 - 460)	310 - 420	300 - 380	290 - 370
		MCFC 300 kW_{el}	410 (340 - 490)	320 - 450	310 - 400	290 - 370
		PAFC 300 kW_{el}	410 (340 - 500)	320 - 460	310 - 420	300 - 400

[1] Bezieht sich auf die aktuell verfügbaren Informationen und moderne Technologie; Stromproduktionskosten beziehen sich auf heute neu gebaute Anlagen (Referenzjahr 2018).
[2] Technisch kaum beschränkt; Schätzung gültig für den Ersatz heutiger Öl- und Gasheizungen in Haushalten.
[3] Berücksichtigt werden Kosten für Investitionen, Brennstoff, Entsorgung, Wartung und Betrieb. Die Bandbreiten reflektieren optimistische bzw. pessimistische Technologiespezifizierung und -entwicklung sowie die angenommenen Veränderungen der Kosten gegenüber heute.
[4] Ergebnisse gelten für Erdgas als Brennstoff. Mit Biogas erhöhen sich die Kosten um 8-14 Rp./kWh.
[5] Treibhausgasemissionen werden hier als Hauptindikator für die Umweltauswirkungen ausgewiesen; weitere Indikatoren sind im Technologiekapitel enthalten. Alle Indikatoren werden mit Ökobilanzen berechnet. Die angegebenen Bandbreiten reflektieren Unterschiede in den Spezifikationen verschiedener Brennstoffzellentypen und mögliche zukünftige Entwicklung. Zum Vergleich: Der heutige Schweizer Stromversorgungsmix (inkl. Importe) weist eine THG-Intensität von rund 100 g $CO_{2eq.}$/kWh auf (Niederspannung). Da hier nur gerundete Werte angegeben werden, spiegeln sich nicht alle kleinen Änderungen der Kosten einzelner Technologien aufgrund aktualisierter Wirkungsgrade in den THG-Emissionen wieder.
[6] Emissionen werden auf Strom und Wärme anhand des Exergiegehalts aufgeteilt.
[7] Treibhausgasemissionen berechnet mit Systemerweiterung: Die Emissionen der entsprechenden Wärmemenge einer Gasheizung werden von den Gesamtemissionen der Brennstoffzellen abgezogen.
[8] Treibhausgasemissionen bei einem Betrieb mit Biogas nehmen um 32-34% ab.
[9] Nach Kap. 11.1; Aufschlag von 75 CHF/MWh für Biomethan.

7 Preface and introduction

7.1 Goal and scope

This report contains an update of electricity generation costs ("Levelized Costs of Electricity", LCOE), previously being part of the analysis of electricity generation potentials, costs and environmental burdens, carried out 2015-2017 on behalf of the Swiss Federal Office of Energy (SFOE) (Bauer et al. 2017). Updating LCOE for some generation technologies appeared to be necessary due to rapid technology development on the one hand and new available data on the other hand. This update was commissioned by the SFOE, mainly in order to be able to use latest information and data for their new energy perspectives ("Energieperspektiven"). The new results are also supposed to be used within the Swiss Competence Centers for Energy Research (SCCER).

Methodology for quantification of LCOE basically remains unmodified (see section 5 in (Bauer et al. 2017)); however, together with assumptions and input data commonly used for all technologies, it is outlined more explicitly here again in section 8. This report focuses on new information and data and primarily refers to electricity generation costs (and technology as far as relevant in the LCOE context); generation potentials have only been updated for roof-top photovoltaic installations as well as hydropower; environmental aspects have not been addressed (apart from the fact sheets, which in addition to partially new LCOE and generation potentials also contain life cycle greenhouse gas emissions according to (Bauer et al. 2017)).

In line with the previous analysis, this report contains current LCOE (calculated whenever possible with data from 2018 as reference year; alternatively, from 2017) as well as "expected" LCOE until 2050. In addition and whenever relevant, new sensitivity analysis regarding the main cost drivers has been carried out for technologies with updated LCOE.

Following a consultation with SFOE, electricity generation costs have been updated for the following technologies:

- Wind power (onshore Switzerland and offshore for imports)
- Solar photovoltaics (PV)
- Natural gas Combined Cycle (NGCC) power plants and combined heat and power generation (CHP) units
- Natural gas fueled Fuel Cells (FC)

In consultation with SFOE, based on their priorities and after a first screening of technology and fuel costs it has been decided not to update LCOE for other technologies, which were addressed in the previous analysis, namely hydro power, electricity from biomass, deep geothermal power, coal and nuclear power, wave and tidal power, concentrated solar thermal power and novel technologies. LCOE of these technologies according to (Bauer et al. 2017) are assumed to be still valid.

This update of LCOE has been reviewed by several experts from the SFOE and internally within PSI. Nevertheless, the authors of this report are solely responsible for its content.

7.2 Acknowledgement

The authors thank the Swiss Federal Office of Energy (SFOE) and the Swiss Competence Center for Energy Research (SCCER) "Supply of Electricity – SoE" for funding this work. In particular, we thank Lukas Gutzwiller from SFOE for his accurate project management and the coordination of SFOE activities supporting this update of LCOE. Furthermore, very useful input data, contacts as well as review comments provided by C. Bühlmann, M. Geissmann, W. Hintz, K. Faust, L. Perret (all SFOE) are acknowledged.

8 Methodology

8.1 General approach for quantification of electricity generation costs

Quantifying Levelized costs of electricity (LCOE) is based on an established method, usually used for comparing electricity generation costs of different technologies with specific cost structures. The LCOE concept reflects the break-even price that must be achieved as average revenue to yield a zero-net-present value (NPV) for equity investors (Comello et al. 2017). The LCOE can be used as a generic economic indicator for comparing the unit costs of different technologies over their operating life. These costs are discounted to the expected commercial operation of a power plant. The LCOE methodology reflects generic technology risks, not specific project risks in specific markets (IEA 2015). Nevertheless, LCOE remains a transparent consensus measure of power generation costs and a widely used tool for comparing the costs of different electricity generating technologies in modelling and policy discussions.

LCOE are calculated the following way:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t + C_t + D_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where the different variables indicate:

LCOE Levelized Cost Of Electricity (here in [CHF/kWh])

I_t Investment expenditures in the year t

M_t Operations and Maintenance expenditures in the year t

F_t Fuel expenditures in the year t

C_t Carbon emission expenditures in year t

D_t Decommissioning expenditures in year t

r discount or interest rate

n lifetime of power plant

Within this analysis, a discount rate of 5% is used, commonly for all generation technologies. For PV installations, which might be associated with comparatively lower investment risks, sensitivity analysis is explicitly carried out with an interest rate of 2% (see section 10). Other parameters are technology specific and discussed in the individual technology sections.

8.2 Cogeneration – heat credits

The same approach as is (Bauer et al. 2017) is used for cogeneration units, generating heat and electricity at the same time (natural gas fueled CHP engines and fuel cells): It is assumed that the heat can replace heat or fuel (i.e. natural gas) that would otherwise have to be purchased and an equivalent credit is applied.

9 Wind power

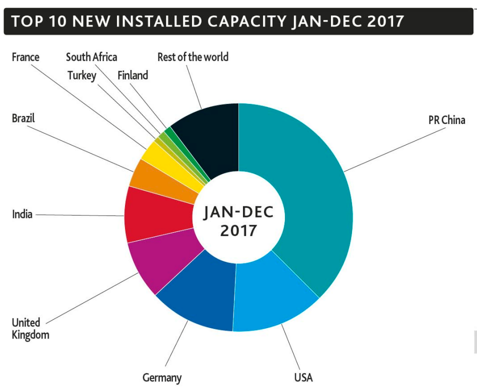
Christian Bauer, Laboratory for Energy Systems Analysis, PSI

9.1 Introduction

Updates in this report for wind power compared to the previous analysis (Bauer et al. 2017) mainly refer to new estimates for LCOE of wind power in Switzerland taking into account recent technology development as well as latest developments in offshore wind power suggesting somewhat lower LCOE than previously estimated.

9.2 General development

While wind power continues to grow substantially on the global scale (Figure 9.1), this trend can hardly be observed in Switzerland. The overall installed capacity of large wind turbines in Switzerland was 75 MW at the end of 2017. In 2017, these turbines generated 132 GWh.[27] The last large turbines were installed in 2016 (Figure 9.2) at the wind parks Mt. Crosin[28] and Gries[29] (20.25 MW in total, partially replacing old, smaller turbines, representing a net increase of installed capacity of about 14 MW).



Country	MW	% Share
PR China	19,660	37
USA	7,017	13
Germany	6,581	12
United Kingdom	4,270	8
India	4,148	8
Brazil	2,022	4
France	1,694	3
Turkey	766	1
South Africa	618	1
Finland	535	1
Rest of the world	5,182	10
Total TOP 10	**47,310**	**90**
World Total	**52,492**	**100**

Source: GWEC

Figure 9.1: Globally new installed wind power capacity in 2017.[30]

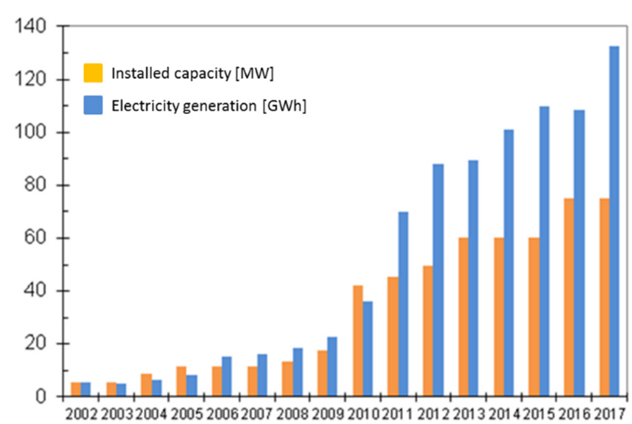


Figure 9.2: Development of wind turbine capacity and wind power generation since 2002 in Switzerland.[31]

[27] http://www.suisse-eole.ch/de/windenergie/statistik/
[28] https://api3.geo.admin.ch/rest/services/ech/MapServer/ch.bfe.windenergieanlagen/facility_MTC/extendedHtmlPopup?lang=de
[29] https://api3.geo.admin.ch/rest/services/ech/MapServer/ch.bfe.windenergieanlagen/facility_GRI/extendedHtmlPopup?lang=de
[30] http://gwec.net/global-figures/graphs/
[31] http://www.suisse-eole.ch/de/windenergie/statistik/

9.3 Electricity generation costs

9.3.1 Onshore – Turbines located in Switzerland and other European countries

9.3.1.1 Current LCOE

Despite of the lack of a large sample of cost data for newly installed turbines in Switzerland, it can be stated that current LCOE of onshore wind power in Switzerland are obviously higher than in most other countries. Kost et al. (2018) report LCOE of 4-8 €$cents_{2018}$/kWh for new onshore turbines in Germany; IRENA (2018) reports global average onshore LCOE of 0.06 $\$_{2016}$/kWh with a range of 0.05-0.15 $\$_{2016}$/kWh. LCEO of current onshore turbines in Switzerland – referring to those turbines recently installed, but also to projects already in development – are in the order of 15-20 Rp/kWh (suisseéole 2019a). Reasons for this "Swiss premium" are manifold. One factor is that in Switzerland wind parks are much smaller than in other countries (some Swiss locations even have only one single turbine)[32], which increases generation costs per kWh. Lower wind speeds in Switzerland and therefore lower yields are another obvious reason. Less obvious reasons (such as delays in permission and construction processes due to e.g. public opposition, or non-permission of single turbines within a wind park) have recently been evaluated and their impact on LCOE has been quantified (Wüstenhagen et al. 2017). Their analysis concluded "that typical complications in the planning and permitting process can increase the cost of an average wind project by 13-49%" (Wüstenhagen et al. 2017). As an example of these complications: "The pre-construction stage of a wind energy project in Switzerland stretches to about a decade, which is more than twice as long as the European average of 4.5 years" (Wüstenhagen et al. 2017). They conclude that accelerating the development of wind power in Switzerland first of all requires a reduction of investment risks, potentially reducing LCOE of wind power, by simplifying and streamlining permitting procedures, creating regulatory clarity, and expediting court cases.

9.3.1.2 Future LCOE

Recent technical developments will be beneficial for wind power in Switzerland: It can be expected that due to improved turbines for sites with – compared to global averages – low wind speeds LCOE of future onshore turbines in Switzerland will be substantially lower than today. These technical developments mainly refer to larger turbines with longer rotor blades and higher towers with lower costs. Wind power projects, which are already in development, can hardly profit from these development, since installing larger turbines than originally permitted usually means that permission procedures have to be repeated (suisseéole 2019a). Considering the usually extensive development period of about 8-10 years, only wind parks starting operation after around 2030 will profit from these technical improvements.

According to (suisseéole 2019a), LCOE of such future (starting operation around 2030) wind parks with 5-10 turbines à 3 MW will be in the range of 10-13 Rp./kWh[33] at typical sites in Switzerland. In these calculations, investment costs for turbines of 1730 CHF/kW and operation/maintenance costs of 4 Rp/kWh are assumed; in addition, costs for planning and permission procedures of 4.6-5.6 Mio. CHF per wind park have been considered. Currently, wind power in Switzerland is often generated with single turbines, which cannot profit from wind park specific synergy effects in construction, planning and permission. Also a large fraction of the generation potential is based on single turbines according to the original – in the meanwhile somehow outdated – "Konzept Windenergie Schweiz" (SFOE 2004)[34]. Usually, LCOE of single turbines are a few Rp./kWh above those of wind parks. We therefore

[32] https://map.geo.admin.ch/?topic=ech&lang=de&bgLayer=ch.swisstopo.pixelkarte-farbe&layers=ch.swisstopo.zeitreihen,ch.bfs.gebaeude_wohnungs_register,ch.bafu.wrz-wildruhezonen_portal,ch.swisstopo.swisstlm3d-wanderwege,ch.bfe.windenergieanlagen&layers_visibility=false,false,false,false,true&layers_timestamp=18641231,,,,&E=2660000.00&N=1190000.00&zoom=2

[33] Calculation procedures for quantification of LCOE in (suisseéole 2019a) are not exactly the same as in this study (section 8), but using the input values provided by (suisseéole 2019a) in the calculation procedure of this study results in almost the same LCOE. Therefore, the range of 10-13 Rp/kWh seems to be plausible and representative for future wind parks in Switzerland.

[34] According to (suisseéole 2019b), wind speeds in the "Windatlas Schweiz" (www.windatlas.ch) are partially substantially underestimated. As a result, generation potentials and generation costs based on this source of data might be under- and overestimated, respectively. Wind power projects should therefore always be based on a detailed, local evaluation of conditions.

estimate LCOE of Swiss wind power in 2035 in the range of 10-15 Rp./kWh with only marginal reductions afterwards in line with the international development.

9.3.2 Offshore – Electricity imports

9.3.2.1 Current LCOE

Most recent and reliable sources provide current global offshore wind power LCOE in the range of 8-20 €cents/kWh[35], see also Figure 9.5 (Kost et al. 2018, IRENA 2018, Wiser et al. 2016, Hendleby & Freeman 2017, Stehly et al. 2016, NREL 2018); the new World Energy Outlook (OECD/IEA 2018) provides average offshore wind power costs of 15 $cents/kWh (for Europe in 2017). Compared to the figures previously reported (Bauer et al. 2017), this indicates a quite substantial reduction of LCOE.

This trend is also supported by significant decline of winning auction prices for offshore wind bids, commonly referred to as "strike prices[36]", as shown in Figure 9.3 for recent European projects (Musial et al. 2017). Key factors that may have contributed to these low bid levels include an optimistic expectation of future turbine sizes, reduced financing costs, optimized and integrated wind farm controls, and the option of not executing the tender (Musial et al. 2017).

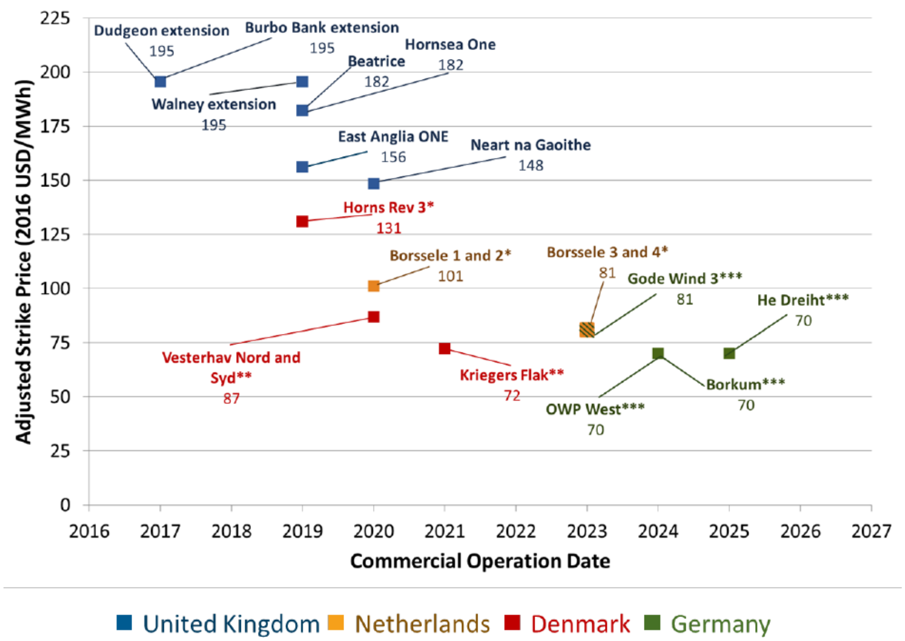


Figure 9.3: Adjusted strike prices from European offshore wind auctions. Source: (Musial et al. 2017). *Grid and development costs added; **Grid costs added and contract length adjusted; ***Development costs added[37].

It is often unclear, whether currently quantified LCOE include offshore wind park end-of-life costs (i.e. those for decommissioning). However, a recent analysis showed that decommissioning costs for offshore wind parks in the UK will be minor and are expected to be in the order of 1-4.4% of LCOE (ARUP 2018).

[35] US$ were converted into € using an exchange rate of 1.15 $/€. Since LCOE were reported for 2016-2018 and inflation has been low, the numbers have not been adjusted.

[36] The strike price for an offshore wind project from an auction is usually the lowest bid price at which the offering can be sold. The strike price usually covers a specific contract term for which that strike price will be paid for the electricity produced. The offeror of that strike price is awarded the rights to develop a particular parcel under predetermined conditions set in the tender offer that may vary by country or market. The strike price should not be confused with LCOE, which may be calculated using different financing and cost assumptions (Musial et al. 2016).

[37] "Note that these strike price adjustments for Germany do not include export system and land-based grid connection costs between the offshore sub-station to shore, which are paid for by the grid operator in Germany. Therefore, the "adjusted" strike price levels are likely underestimated." (Musial et al. 2017).

9.3.2.2 Future LCOE

Future offshore wind power LCOE are expected to decrease. However, estimations vary over a large range as shown in Figure 9.4.

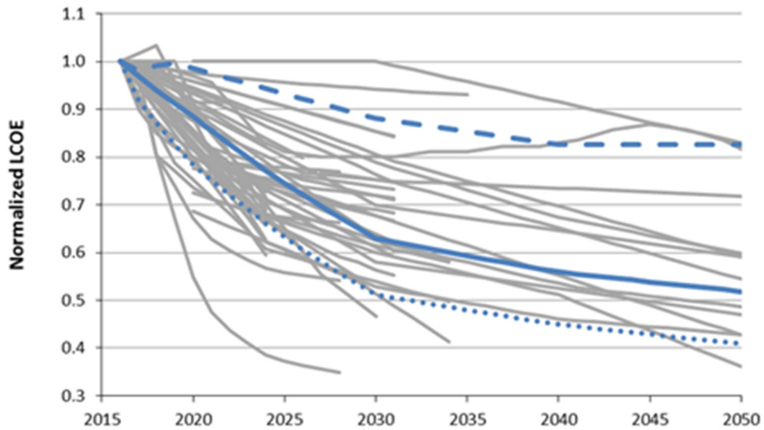


Figure 9.4: Offshore wind power cost projections from various sources; blue: NREL projections; grey: recent literature. Source: (NREL 2018).

Most recent projections are shown in Figure 9.5 (together with current LCOE); latest estimates of the International Energy Agency are within those ranges: LCOE of 9 $cents/kWh are expected for average European offshore wind power in year 2040. It should be kept in mind that such projections and the underlying level of optimism can be driven by specific, non-disclosed interests of the authors of a specific analysis. Estimates for 2050 from reliable sources are rare.

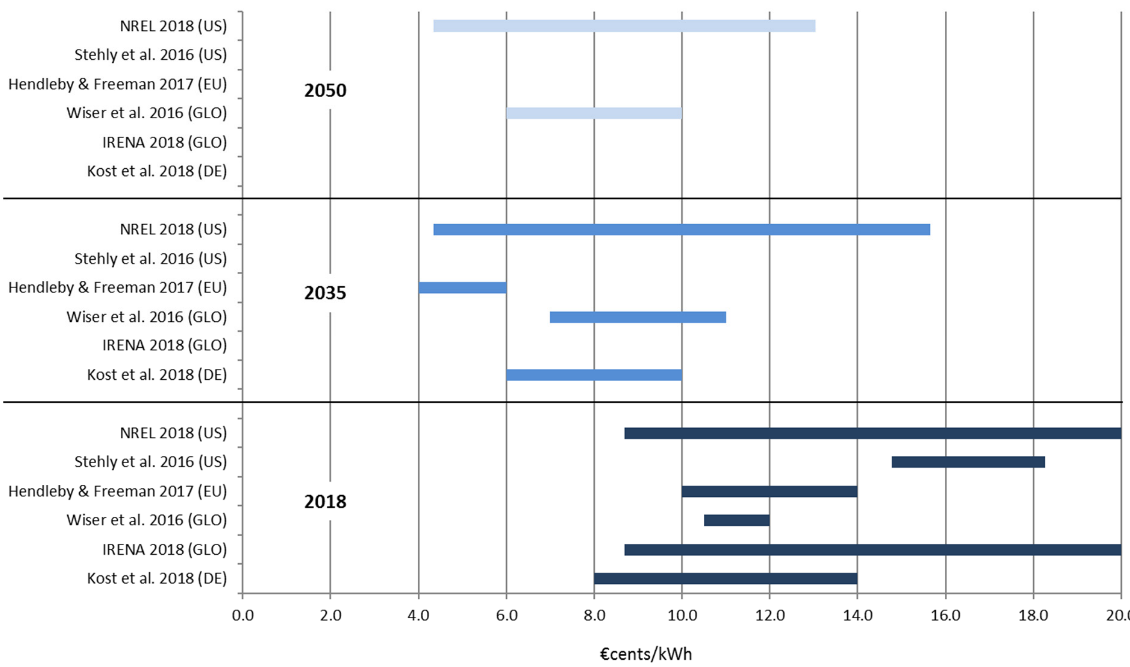


Figure 9.5: Current and future LCOE of offshore wind power accoording to various sources (Kost et al. 2018, IRENA 2018, Wiser et al. 2016, Hendleby & Freeman 2017*, Stehly et al. 2016*, NREL 2018). *LCOE shown in this graph represent extrapolations from 2030 figures in these sources.

10 Solar photovoltaics (PV)

Xiaojin Zhang, Laboratory for Energy Systems Analysis, PSI

10.1 Introduction

In the context of PV electricity generation costs, the previous analysis (Bauer et al. 2017) faced some shortcomings: Although abundant references for LCOE in other countries and for general cost development of PV technologies were available, specific cost data valid for Switzerland was limited. As a result, for example, sampled costs from online offers and reference system investment costs from the "kostenorientierte Einspeisevergütung (KEV)" had to be used as source of system capital costs. Since 2017, a few new references and data that were specific to Switzerland were published or available for this analysis. Therefore, an update of the current and future PV cost development could be performed, which should be useful given the constantly fast PV cost development. The following sections will explain in detail which data and assumptions have been updated compared to the previous analysis (Bauer et al. 2017), and what the implications on the resulting levelized cost of electricity (LCOE) for PV are.

Data quality for the current calculations is significantly better than that of the previous analysis. This applies on the one hand to total investment costs – the sample of systems for which investment costs were available was comparatively small in 2016, while several hundred cost data points were now available from SwissEnergy's Solar Offer Check Tool[38]. On the other hand, the allocation of costs to modules, installation, etc. was transferred from large systems to all output classes in 2016, while specific figures are now also available for small systems. This makes the new LCOE calculations much more reliable and meaningful.

In addition to quantification of LCOE and as an extension of the previous analysis, curves for potential PV electricity generation vs. LCOE were generated for today and 2035. These curves fill an important research gap of the previous analysis.

10.2 Electricity generation costs

10.2.1 Current costs

The Swiss Federal Office of Energy has provided a list of investment costs for PV plants offered in Switzerland (SFOE 2018b) with cost data from 357 building-added PV (BAPV) systems from 2018. More than 97% of these systems installed in 2018 have capacities below 30 kW_p (Figure 10.1) and therefore, these data are used for representation of PV investment costs in Switzerland in 2018 ("current") for systems with capacities below 30 kW_p.

[38] https://www.energieschweiz.ch/page/de-ch/solar-offerte-check

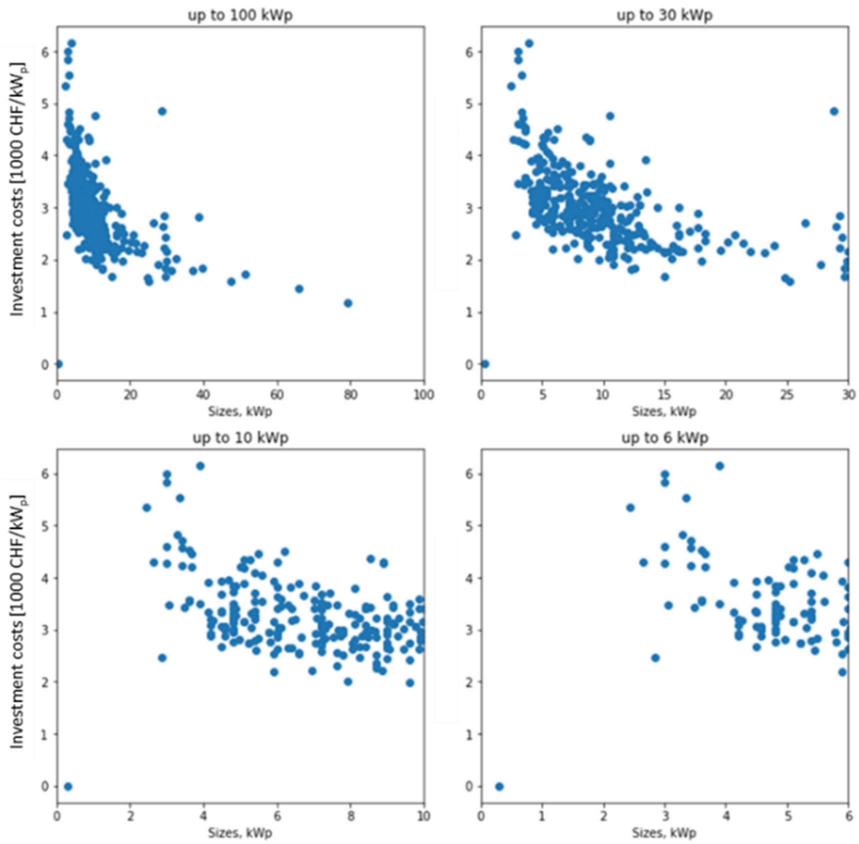


Figure 10.1: BAPV system investment costs of various installed capacities in Switzerland in 2018; from top left to bottom right: capacities up to 100 kW$_p$, 30 kW$_p$, 10 kW$_p$ and 6 kW$_p$.

Table 10.1 and Figure 10.2 give an overview of capital costs for the same set of small PV system capacity categories (6 kW$_p$, 10 kW$_p$ and 30 kW$_p$) as included in the 2017 report. Compared to the assumptions of current costs in the 2017 report, ranges are introduced to reflect the variations due to differences in installing conditions and sales prices and further costs. Here, the costs at 25% and 75% percentile are used as the minimum and maximum current cost to represent the system capital costs today in Switzerland, while the median cost value is used as the basis for future cost projections.

In comparison with the system capital costs for small-scale rooftop PV systems (i.e. systems up to 10 kW$_p$) in Germany of about 2000 EUR/kW$_p$ (Fraunhofer 2018), the median system capital costs in Switzerland are around 30% higher than in Germany, while the minimum system capital costs are on a comparable level.

Table 10.1: Distribution of PV investment costs for various plant capacities up to 30 kW$_p$ according to (SFOE 2018b).

	6 kWp	10 kWp	30 kWp
Number of data	26	66	7
Investment Cost (CHF/kWp)			
mean	3242	2881	2162
std	568	505	386
min	2216	1913	1680
25%	2851	2619	1908
50%	3192	2895	2154
75%	3635	3162	2326
max	4511	4762	2834

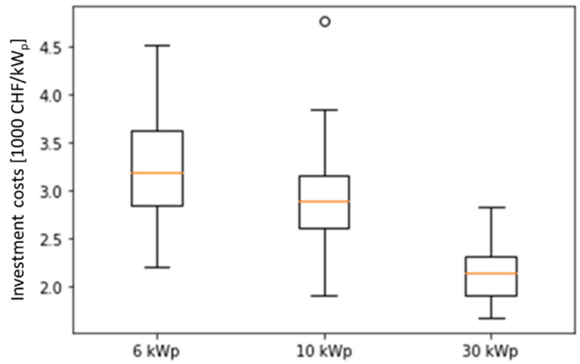


Figure 10.2: BAPV system capital costs of various sizes in 2018 for systems of 6 kW$_p$, 10 kW$_p$, 30 kW$_p$.

For systems with capacities of 100 kW$_p$, two approaches to update the system capital costs were tested:

1. Interpolation with limited data points (i.e.: only 2) around 100 kW$_p$ system size based on the data provided by SFOE (SFOE 2018b): This results in a total system capital cost of around 1080 CHF/kW$_p$, which is lower than the 1 MW$_p$ utility scale PV system capital cost from the National Survey Report (NSR) of Photovoltaic Applications in Switzerland 2017 (Heiniger and Perret 2017), thus assumed not to be representative;
2. Interpolation between system capital cost for 6-30 kW$_p$ and 1000 kW$_p$: This results in a total system capital cost of around 1700 CHF/kW$_p$. Given the limited data points between 70 kW$_p$ and 160 kW$_p$ in 2018 from SFOE (1000-1200 CHF/kW$_p$), this value seems to be too high.

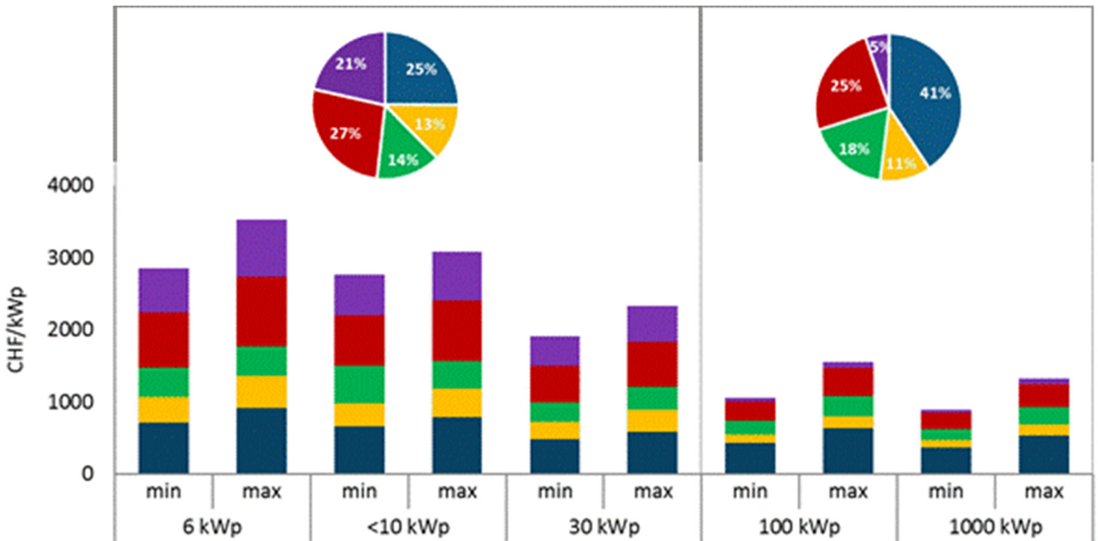
In the end, the total investment cost for systems of 100 kW$_p$ is assumed to be 1300 CHF/kW$_p$ based on expert judgement confirmed by the SFOE. This cost is also comparable with the average cost of PV system ranging from 10-100 kW$_p$ in Germany (1140 EUR/kW$_p$) (Fraunhofer 2018).

For 1000 kW$_p$ systems, the range of system investment costs for installations with capacities above 1 MW$_p$ from the National Survey Report (NSR) of Photovoltaic Applications in Switzerland 2017 (1106 CHF/kW$_p$) is used as representative value (Heiniger and Perret 2017). The same relative variations around average system costs are applied to estimate the range of system investment cost for systems of 100 kW$_p$.

In comparison with the cost in Germany, the system capital cost for small-scale PV systems in Switzerland still remains high, possibly due to the higher labor cost, while the gap of system capital cost for larger PV systems seem to become smaller over the years.

Another improvement compared to (Bauer et al 2017) refers to the overall system investment cost breakdown into different cost components. In the 2017 report, the breakdown for utility-scale PV system was based on (Perch-Nielsen et al. 2014) and applied to systems of all different sizes. In (Heiniger and Perret 2017), system capital cost breakdowns were provided for systems from 5-10 kW$_p$, and systems for more than 1 MW$_p$. The cost breakdowns for system sizes in between were attempted to be interpolated; however, lower module costs for 100 kW$_p$ were obtained than for 1000 kW$_p$ systems based on the interpolated cost breakdowns. Thus, cost breakdowns for 5-10 kW$_p$ are applied to system from 6-30 kW$_p$ and cost breakdowns for system of more than 1 MW$_p$ are applied for systems from 100 kW$_p$ to 1 MW$_p$ (Figure 10.3). These breakdowns show that as system size increases, the share of module cost increases from 25% to 41% of the total investment cost, while the sum of contributions from other costs becomes smaller. This is due to the economy of scale: when system size increases, the cost of modules becomes more important in the overall cost, because the other costs (per kW$_p$) decrease.

Based on the ranges of system capital costs and the cost breakdown, absolute costs for different cost components were calculated and are shown in Figure 10.3.



	6 kWp min	6 kWp max	<10 kWp min	<10 kWp max	30 kWp min	30 kWp max	100 kWp min	100 kWp max	1000 kWp min	1000 kWp max
Other	612	781	563	679	401	488	53	77	46	67
Labor	762	972	700	845	515	628	263	387	222	328
BOS	405	405	516	372	267	326	189	279	162	238
Inverter	357	455	328	396	248	302	116	170	101	149
Module	714	911	656	792	477	582	431	635	364	536

Figure 10.3: BAPV system investment costs in 2018 used in this analysis for calculation of current LCOE.

Annual O&M cost has further decreased and according to latest numbers for 2018 (Toggweiler 2018), 3 Rp. per kWh of electricity produced is assumed for system of and less than 100 kW_p and 2 Rp/kWh is assumed for systems of and above 1 MW_p.

Replacement of inverter and part of BOS is assumed to be included as part of the O&M cost (Toggweiler 2018).

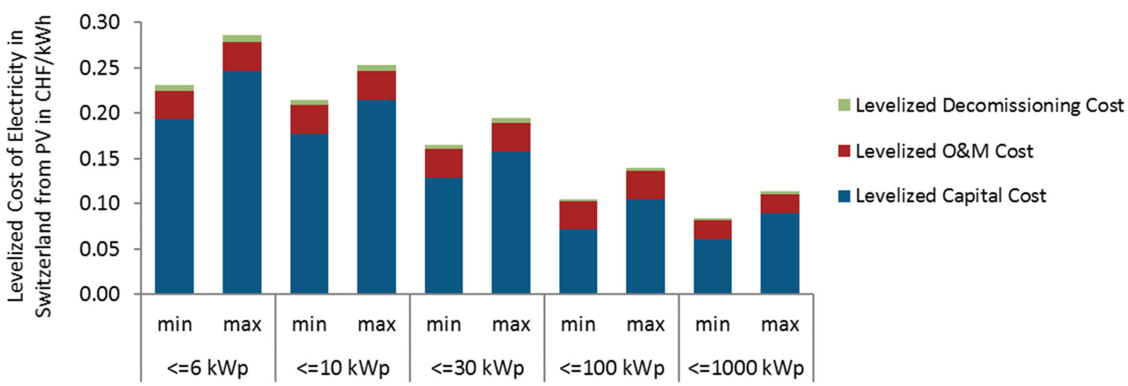
Few other key performance parameters relevant for LCOE calculations were also updated based on (Vontobel et al. 2016), which looked into the actual performance of 1170 PV plants in Switzerland. These updates include an annual average yield of 1013 kWh per kW_p, with an estimated performance ratio of 80%. Current average module efficiency was updated to be 17% (Fraunhofer 2018), and the area required per m^2 is updated accordingly to 6 m^2/kW_p. Ranges of module efficiencies (13-21%) based on the products available on the Swiss market were taken into account in the sensitivity analysis. Because these updated parameters are closely associated with the average annual solar irradiance for all PV systems in Switzerland (i.e.: in order to reach the updated yield assumed, average solar irradiance has to reach a certain level given the module efficiency, performance ratio and unit area required per kW_p), average annual solar irradiance had to be adjusted to be 1267 kWh/m^2 per year, as opposed to the average value for Mittelland of 1100 kWh/m^2 per year. This increase is considered to be acceptable, because according to the distribution of these 1170 PV plants in Switzerland (Vontobel et al. 2016), there are quite some plants located outside of the Mittelland (e.g., in Ticino). To be explicit on the assumptions updated and used in this analysis, a summary comparing the key assumptions used in 2017 as well as in this new analysis is shown in Table 10.2.

Table 10.2: Overview of key parameters for LCOE calculations in both the previous (Bauer et al. 2017) and this new analysis.

Data	Previous analysis (Bauer et al. 2017)	Updates used in this analysis
Current system investment cost	Online offers for residential-scale systems (e.g., single family house) 6 kW: 2583 CHF/kWp 10 kW: 2092 CHF/kWp KEV in Oct 2016: 30 kW: 1815 CHF/kWp 100 kW: 1410 CHF/kWp 1000 kW: 1350 CHF/kWp	System up to 30 kWp: system capital costs data provided by SFOE in Nov 2018 (average figures) 6 kW_p: 3192 CHF/kWp 10 kW_p: 2895 CHF/kWp 30 kW_p: 2154 CHF/kWp System 100 kW_p: 1300 CHF/kW_p (expert judgement confirmed by SFOE, Dec 2018) System 1 MW_p: 1106 CHF/kW_p according to (Heiniger and Perret 2017) More than 1 MW_p: 1000 CHF/kW_p (own assumption given data provided by SFOE in Nov 2018), used for sensitivity analysis
Percentage breakdown of current system investment cost by module, inverter, BOS, labor and other costs	Breakdown of costs: Module: 46% Inverter: 10% BOS: 15% Labor: 22% Other costs: 7% assumed to be the same for all sizes	Values based on (Heiniger and Perret 2017) for systems smaller than 10 kW_p were applied to systems ranging from 6-30 kW_p, and values for systems larger than 1 MW_p were applied to systems from 100 kW_p to 1 MW_p. Detailed cost breakdowns by system sizes are shown in Figure 10.3.
Annual O&M cost	Rp/kWh of electricity produced 6-10 kWp: 10.6 30 kWp: 8 100 kWp: 4.3 1000 kWp: 1.5	Based on (Toggweiler et al. 2018): 3 Rp/kWh for small systems (<=100 kW_p) 2 Rp/kWh for systems larger than 100 kW_p
Replacement cost	Replacement is needed every 15 years: Inverter: new inverter is needed BOS: 10% of BOS capital cost Labor: 10% of total replacement costs for inverter and BOS	none (as this is included as part of the O&M cost according to (Toggweiler et al. 2018)
Decommissioning cost	Cost for labor: 50% of labor cost in system capital investment Cost for disposal is assumed to equal to the residual value of the entire system	No update
Other key assumptions	interest rate: 5% annual electricity production degradation rate: 0.5% area required per kWp installation: 7.5 m2/kWp average module efficiency: 15% average inverter efficiency: 98% lifetime: 30 years performance ratio: 80% average annual solar irradiance: 1100 kWh/m2 per year annual yield: 970 kWh/kWp	Annual avg. yield: 1013 kWh/kW_p (Vontobel et al. 2016) Performance ratio: 80% (Vontobel et al. 2018) Area required per kW_p installation: 6 m^2/kW_p (suggested by SFOE, Oct 2018) Average module efficiency: 17% (Fraunhofer 2018), range 16%-18% for current cost in order to match the yield above: the following values have to be assumed Average annual solar irradiance: 1267 kWh/m^2/year (reference: Mittelland: 1100 kWh/m^2/year; Swiss Alps: 1400-1600 kWh/m^2/year) Interest rate: in addition to the default value of 5%, consideration of 2% as sensitivity for current LCOE Other parameters: no updates

The current LCOE discussed in this report represent roof-top, building-added PV systems (BAPV). The LCOE for building-integrated PV (BIPV) systems will be different (higher by trend) due to several factors including capital cost per kW_p (which is often considered as additional capital cost and varies depending on whether it is a new or retrofitted building and the construction component it substitutes), potential reduction of solar irradiance received due to non-optimal module orientation, decreased module efficiency as BIPV systems usually use thin-film PV modules rather than silicon-based modules as opposed to the reference systems in this analysis, etc. A detailed analysis of all those factors and their impact on potential LCOE of BIPV is out of scope of this cost assessment.

The LCOE for different sizes of BAPV systems are shown below. Since the interest rate for PV systems – especially for small systems (e.g., PV system installed for single family house) – might be lower than 5%[39], two sets of results are provided here given two options of interest rate (top: 5%; bottom: 2%). The LCOE ranges from 8-29 Rp/kWh with interest of 5%, or 7-22 Rp/kWh with interest of 2%. Compared to the previous results in 2017, 6-32% and 27-45% of reduction of LCOE, respectively, can be observed. This decrease in LCOE is mainly because the O&M costs in this analysis are substantially lower than previously assumed due to more up-to-date data (Toggweiler et al. 2018). In addition, replacement costs are excluded as it is assumed to be covered by the latest O&M cost (Toggweiler et al. 2018).



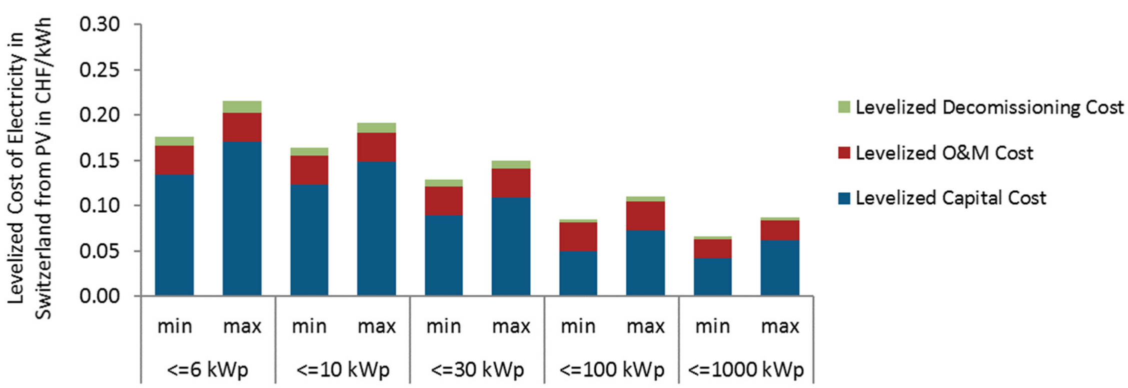


Figure 10.4: LCOE of BAPV systems with various capacities in 2018 (top: 5% as interest rate; bottom: 2% as interest rate); ranges are based on potential ranges in investments costs (25% and 75% figures in Table 10.1, respectively).

Sensitivity analysis was performed using the median costs and system parameters for the 10 kW_p system as baseline values, and the results are shown in Figure 10.5. The 10 kW_p system was used as a reference size in this study as opposed to 100 kW_p in the 2017 study as most of the BAPV systems in Switzerland are less than 30 kW_p (Figure 7.1) and sensitivity analysis based on 10 kW_p may provide

[39] An interest rate of 5% is used as baseline for all technologies considered in this analysis.

more insights for resident investors that are interested in installing PV systems for their homes. Compared to the sensitivity analysis in the previous analysis, overall trends in sensitivity of LCOE to various parameters remain the same. Some minor absolute changes can be seen, all as a result of the updated assumptions applied in this analysis: 1) the curves for some parameters (e.g., solar irradiance, module efficiency) shifted towards the side of lower ratio to baseline and higher LCOE mainly due to the increased value of baseline assumptions; 2) the upper limit of capital cost increased due to better quality of data for smaller systems; and 3) the lower limit of capital cost decreased due to continued decreasing system investment cost for utility-scale systems.

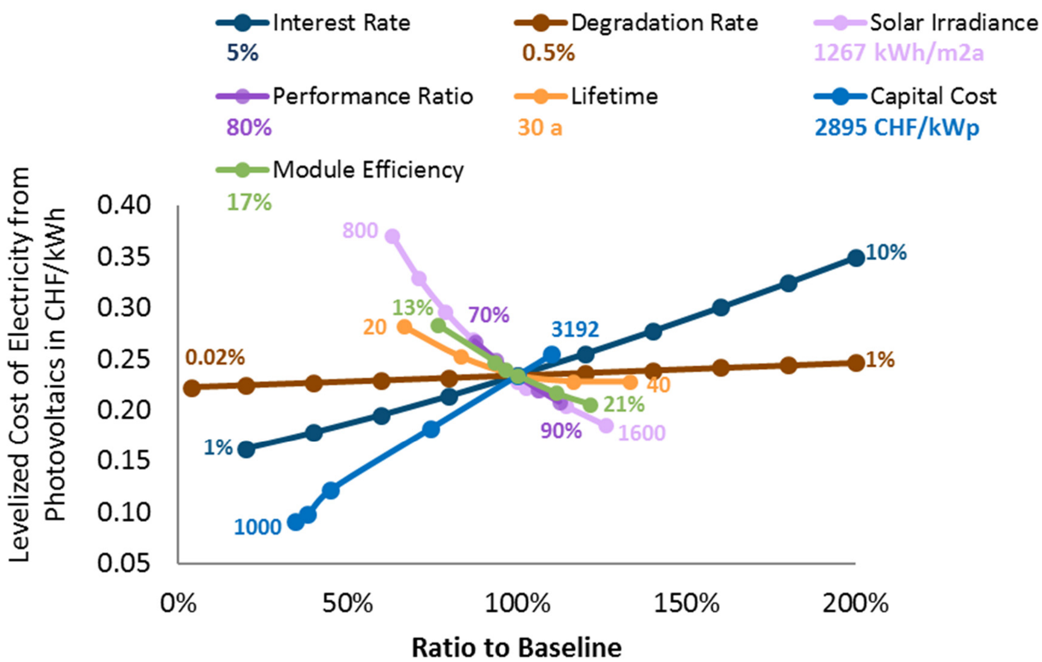


Figure 10.5: Sensitivity analysis for LCOE of a 10 kW_p BAPV system in 2018.

10.2.2 Future costs

For the estimation of future LCOE, the assumptions in terms of learning rates for different cost components from the previous analysis (Bauer et al. 2017) are also applied in this new analysis. However, "baseline" values for future cost projections are different (2018 costs instead of 2015/16 costs).

Although the total system investment costs for PV systems smaller than 30 kW_p are slightly higher in this analysis compared to the previous study (Bauer et al. 2017) due to better and more representative data in Switzerland, future module costs projected are lower; this is a result of the updated cost breakdowns applied: The share of module cost in total system cost is lower, which even outperforms the increased system capital cost and leads to lower current module costs for systems smaller than 30 kW_p. For larger systems, as the system capital cost decreased since 2017 and the percentages of cost component more or less remain the same, the current module costs have decreased. Since these current module costs are used as basis for future projections of module costs, a future module cost reduction of 18-36% can be observed compared to the previous future module costs projected in 2017.

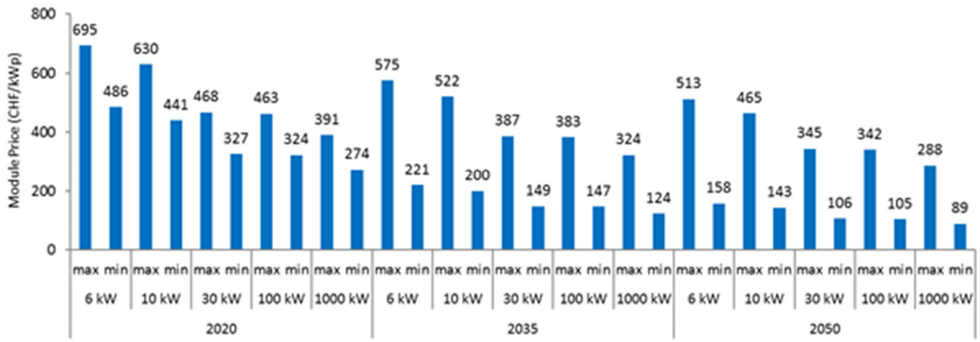


Figure 10.6: Future estimated maximum and minimum module costs for various installation sizes in Switzerland, 2020-2050.

The total capital costs in the future for different system sizes are shown below. Since module costs in the future will further decrease, the other cost components are getting even more important in the overall system capital costs than in the previous analysis. Due to the increased current system investment costs for systems of and less than 30 kW$_p$, the future system capital costs projected by 2050 for these small systems will be higher than previously projected, whereas for 1 MW$_p$ systems, the system capital costs will be below the previously estimated values.

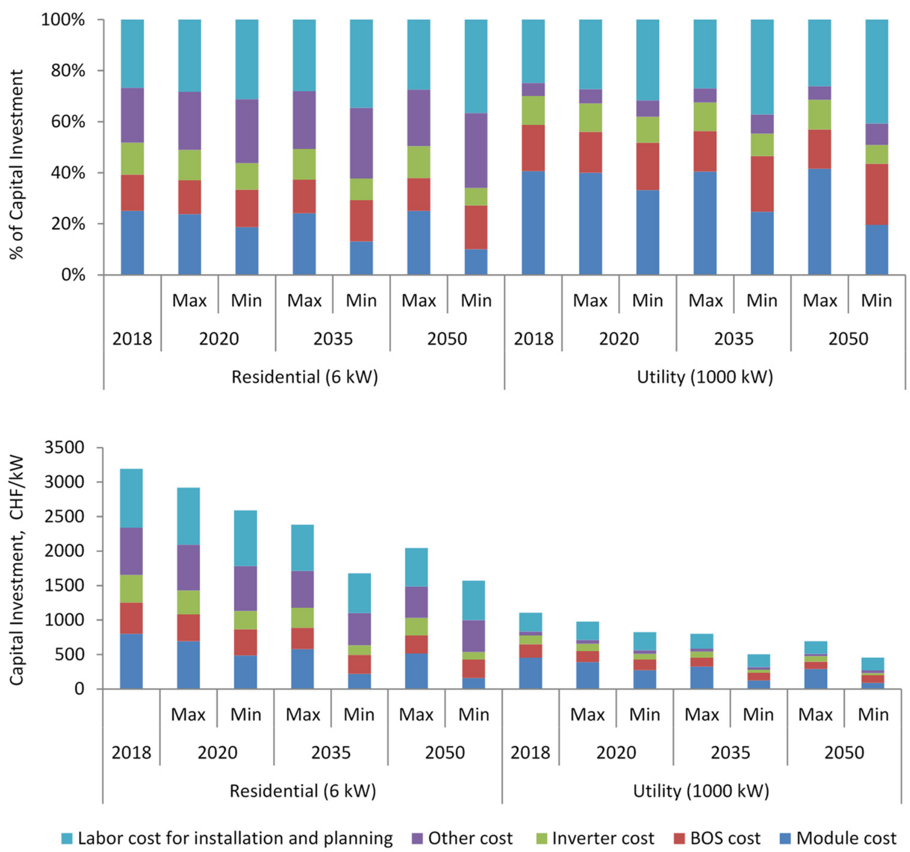


Figure 10.7: Current and future overall capital costs (bottom) for both residential-scale PV systems (represented by a typical size of 6 kW$_p$) and utility-scale PV systems (represented by a size of 1000 kW$_p$) and relative breakdown by cost component (top).

Correspondingly, future LCOE of larger PV installations show a more substantial decrease than those of smaller installations compared to the previous analysis in 2017, with LCOE in the range of 8-24 Rp/kWh in 2020 and 4-16 Rp/kWh in 2050 depending on the capacities of the systems.

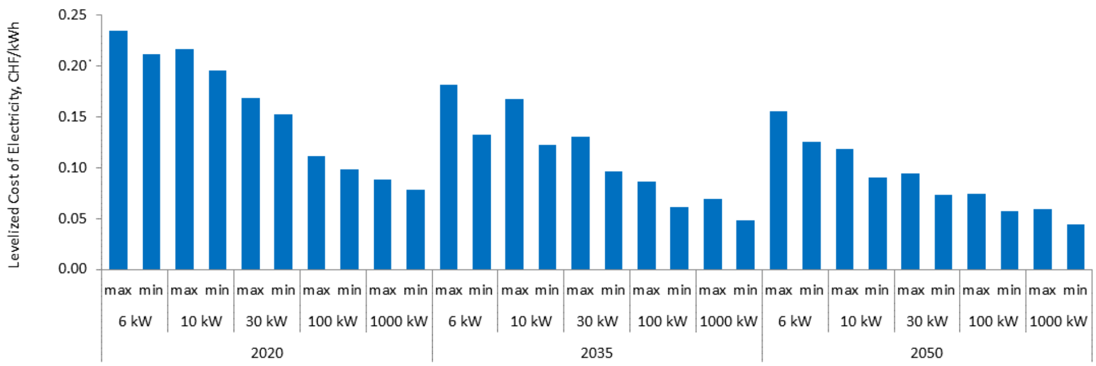


Figure 10.8: Future LCOE from PV power in Switzerland: minimum and maximum values, 2020-2050.

Analyzing the origin of LCOE reduction in the future (Figure 10.9) shows that the largest reduction in LCOE is due to the estimated reduction of PV module prices. This is in general the largest cost reduction driver for all PV plant sizes included in this analysis.

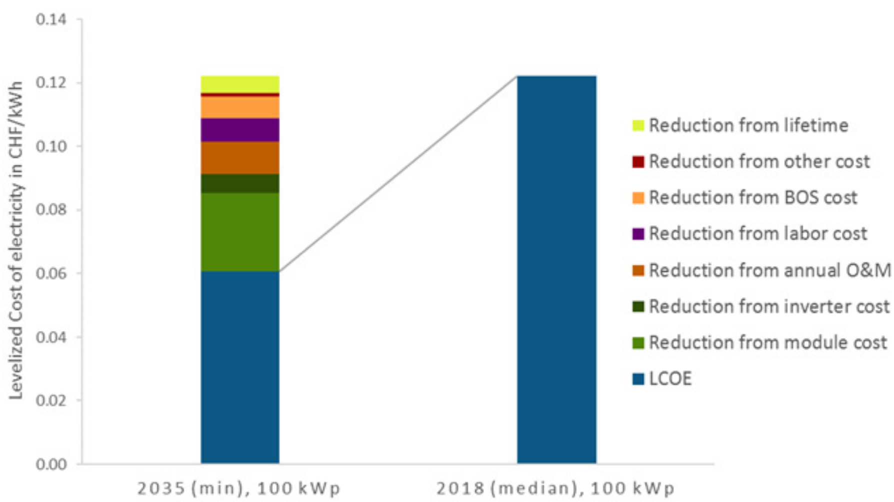


Figure 10.9: Future LCOE reduction by cost component: example from lower estimate of LCOE in 2035 (minimum) vs. LCOE in 2018 for a 100 kW$_p$ system.

10.3 Annual electricity production potential vs. levelized cost of electricity (LCOE)

Thanks to newly available data regarding roof-tops for the entire Switzerland (www.sonnendach.ch, meteotest 2016) and the new estimates for PV module costs, efficiencies and other parameters, cost-potential curves for roof-top PV installations in Switzerland could be established; these curves are supposed to fill a gap in research previously highlighted in (Bauer et al. 2017).[40] In general, "exploitable" (as specified in (Bauer et al. 2017)) potentials were quantified for all technologies. However, for technologies with highly location-specific LCOE such as PV, these figures are difficult to interpret and use e.g. in energy system models, since electricity generation costs will depend on the

[40] PV potentials vs costs on facades could not yet be quantified in the same way, since the potentially available façade area has not been publicly available in time for this report (https://www.uvek-gis.admin.ch/BFE/sonnenfassade/?lang=en, 6.3.2019).

amount of potential exploited. The cost-potential curves for roof-top PV installations established now will contribute to a more realistic representation of PV in energy scenarios.

The LCOE-dependent potentials quantified in the following are exploitable in the sense that if needed, there would be enough roof-top area to generate these amounts of electricity at the estimated costs; it is assumed that 70% of available roof-top areas can be covered by PV installations[41] – this factor is associated with high uncertainties, though, and potential competing use of roof-tops (e.g., for solar thermal heat collectors) is not taken into account. Whether this will make sense from the economic point of view will depend on future economic boundary conditions. Any potential social concerns and restrictions are not considered. The estimated costs do not include any investments in order to ensure stability of the overall electricity system, which might be required with substantially higher decentralized PV capacities installed. At some point, it might also be necessary to curtail PV generation at peak hours. Addressing such aspects will require the use of energy or electricity system models capturing systemic issues.

The following sections explain in detail how the results of annual production potential vs. LCOE of PV systems in Switzerland were generated. Basically, the cost data from the previous sections were linked to data from sonnendach.ch[42] regarding available roof-top areas with corresponding solar irradiation, resulting in specific LCOE and annual electricity production for each roof-top area. Cost-supply curves were generated for today and 2035 – regarding input numbers, these differ in terms of investment costs, module efficiency and thus required area per kW_p installed and overall generation potential. Table 10.3 provides some key figures in this context.

Table 10.3: Key figures for the quantification of LCOE vs. electricity generation with roof-top PV plants in Switzerland, quantified using data from sonnendach.ch.

Area available (km^2)	all roofs: 451 roofs with solar irradiance >1000 kWh/m^2/year: 326 roofs with solar irradiance >1200 kWh/m^2/year: 181 roofs with solar irradiance >1400 kWh/m^2/year: 39
Installed capacity (GW_p)	all roofs: 75 roofs with solar irradiance >1000 kWh/m^2/year: 54 roofs with solar irradiance >1200 kWh/m^2/year: 30 roofs with solar irradiance >1400 kWh/m^2/year: 6
Electricity generation (TWh/a)	all roofs: 63 roofs with solar irradiance >1000 kWh/m^2/year: 50 roofs with solar irradiance >1200 kWh/m^2/year: 30 roofs with solar irradiance >1400 kWh/m^2/year: 7

10.3.1 Method & Key Assumptions

The following data for each polygon of roof in Switzerland was obtained from the geodatabase from sonnendach.ch (file name: "SOLKAT_20180827.gdb"; layer: "SOLKAT_CH_DACH"):

- Area of roof (FLAECHE[43])
- Total solar irradiance (GSTRALUNG)

[41] This fraction of 70% was provided by SFOE and has been estimated in a survey among experts in the photovoltaic business.
[42] https://www.uvek-gis.admin.ch/BFE/sonnendach/?lang=en
[43] More details about the data fields in the database can be found in the documentation: sonnendach.ch, Datenmodell, Meteotest, Bern 8, Feb 2016 (meteotest 2016) (provided by SFOE).

The data take into account roof-top orientation and slope as well as shading from surrounding buildings and landscape elements. Due to the large amount of data (for more than 9 million roofs in Switzerland), this analysis was carried out through Python script in Jupyter Notebook, with a few open-source packages (fiona, scypy, numpy, pandas).

Installed capacity for each roof was estimated by assuming 6 m^2 per kW_p of installed system for current PV systems (4.4 m^2 for 2035). Based on the system investment cost of various sizes (6, 30, 100, 1000 kW_p), interpolation was performed to look up a corresponding system investment cost for each roof. Since no curve fits well to the data points, 1-D interpolation[44] was performed between each of the sizes (Figure 10.10) for both reference years.

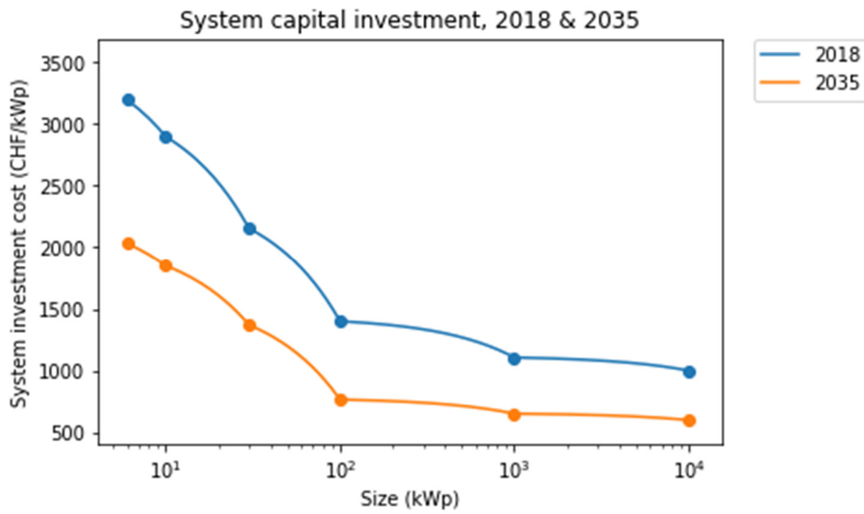


Figure 10.10: PV system capital investment in 2018 and 2035; interpolations between data points appear to be concave due to the logarithmic scale on the x-axis.

In some cases PV systems according to the sonnendach data are outside of the size range of 6-1000 kW_p (for which investment cost data were estimated); then, the following assumptions were applied:

Current cost (2018)

- 0 kW_p < size <= 6 kW_p: 3500 CHF/kW_p < system capital cost < 3192 CHF/kW_p
- 1000 kW_p < size <= 10'000 kW_p: 1106 CHF/kW_p < system capital cost < 1000 CHF/kW_p
- size > 10'000 kW_p: system capital cost = 800 CHF/kW_p

Future cost (2035)

- 0 kW_p < size <= 6 kW_p: 2500 < system capital cost < 2031 CHF/kW_p
- 1000 kW_p < size <= 10'000 kW_p: 652 CHF/kW_p < system capital cost < 600 CHF/kW_p
- size > 10'000 kW_p: system capital cost = 500 CHF/kW_p

LCOE for every roof in Switzerland were calculated for each potential roof-top PV installation. The resulting LCOE were then ranked from low to high, and the potentials of cumulative generation were calculated at various equally-spaced LCOE values in the range of 5-50 Rp/kWh. The following figures show the electricity generation potentials vs. LCOE considering:

[44] scipy.interpolate.interp1d:https://docs.scipy.org/doc/scipy/reference/generated/scipy.interpolate.interp1d.html

1. All the roofs as well as roofs with three different levels of solar irradiance (>1000, >1200 and >1400 kWh/m^2/year, respectively).
2. Current system investment cost and corresponding electricity generation in 2018 (Figure 10.12) and future system investment costs and corresponding electricity generation in 2035 (Figure 10.13). These two calculations were performed due to the fact that not all the roofs in Switzerland will be equipped with solar PV panels given the current costs and module performance; it will take some time to realize the full potential. Over time, the costs will further decrease as the global market of PV develops, and due to technology development, the average module efficiency is assumed to be increased (to 23% in 2035), which results in less area required per kW$_p$ of system installation (4.4 m^2/kW$_p$ in 2035).

10.3.2 Results

In the PV generation potential estimates provided by BFE[45], roofs with less than 10 m^2 of area were excluded. Figure 10.11 shows whether excluding such small roofs does result in substantial differences regarding potentials of electricity generation – obviously, it does not. Nevertheless, the analysis here includes the small roofs with areas below 10 m^2.

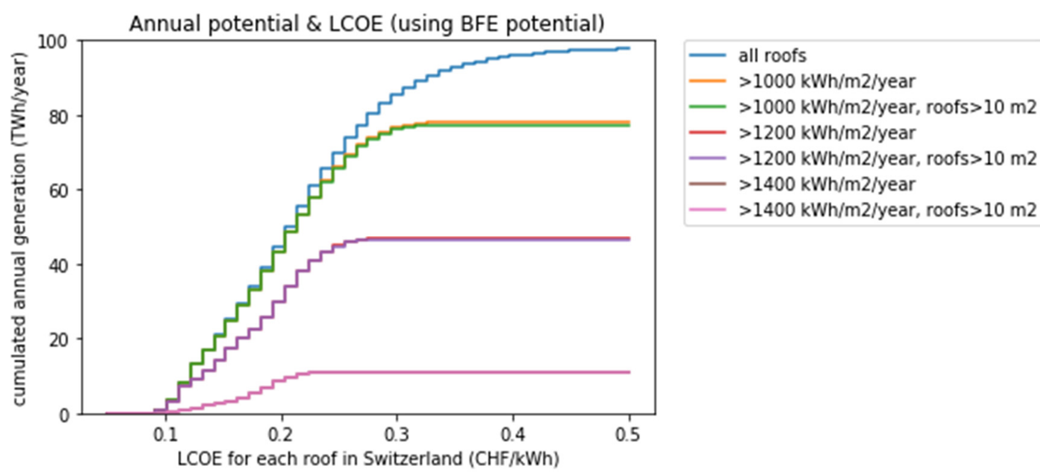


Figure 10.11: Annual electricity generation potential and LCOE for all roofs, solar irradiances of more than 1000, 1200, 1400 kWh/m²/year, and with or without roofs with areas below 10 m², considering system investment cost in 2018.

Figure 10.12 shows the potentials vs. LCOE considering current system investment costs in 2018. Potentials provided by BFE and calculated by PSI are both used in the graphs. The potentials calculated by PSI are slightly lower than the potentials from BFE (originally included in sonnendach data): PSI potentials take into account degradation of PV modules, i.e. reduced electricity generation over the lifetime (0.5% per year) as well as the efficiency loss due to the inverter (2%). Furthermore, LCOE and potentials for two cases are calculated: a) complete coverage of roofs with PV modules; b) roof utilization of 70%, in line with (Portmann et al. 2016). Calculations for case b) (70% roof coverage) consider the fact that the smaller systems installed are, the higher system investment costs and thus the LCOE will be. This factor of 70% should be considered as relatively uncertain. If the average roof utilization factor will be smaller, potentials will be reduced and LCOE will be higher.

[45] Photovoltaik - Annahmen für Modellierung in den Energieperspektiven (v1.3, internal document, draft), provided by SFOE.

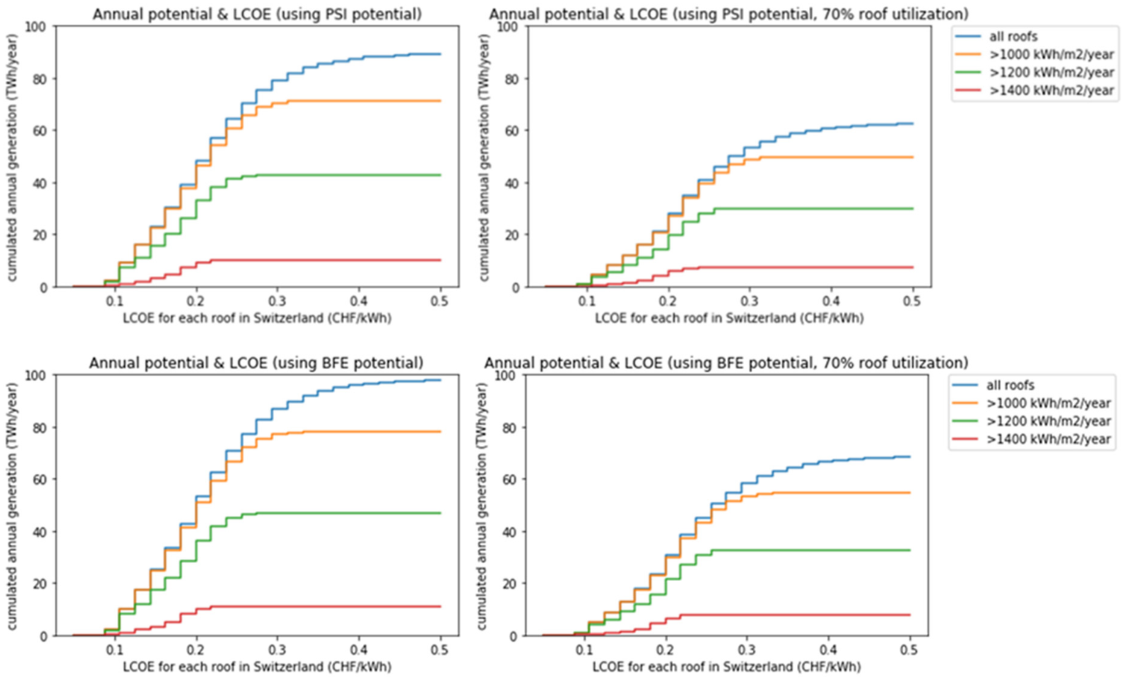


Figure 10.12: Annual electricity generation potential (calculated by PSI (top) and published by BFE (bottom)) and LCOE for all roofs and solar irradiance of more than 1000, 1200 and 1400 kWh/m²/year, considering system investment cost in 2018. BFE potential refers to the generation potential (column STROMERTRAG) originally obtained from the sonnendach data.

Figure 10.13, considering system investment costs in 2035, shows that the full (maximum) potentials are higher than today due to reduced amount of area required per kW_p of system installed. Higher potentials are shown given the same LCOE compared to Figure 10.12, because of the decrease in system investment costs by 2035. In reality, the potential that might be achieved and the corresponding LCOE will probably lie in between the scenarios shown in Figure 10.12 and Figure 10.13.

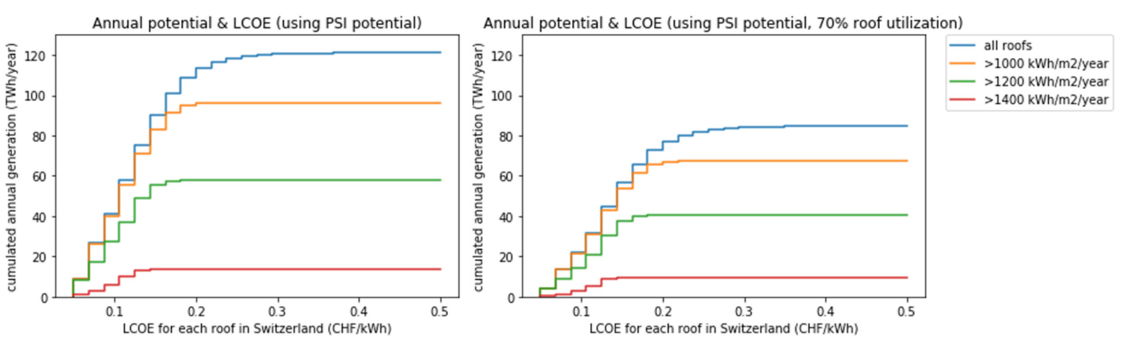


Figure 10.13: Annual electricity generation potential calculated by PSI and LCOE for all roofs and solar irradiance of more than 1000, 1200 and 1400 kWh/m²/year, considering system investment cost in 2035. Note that the potential electricity generation from BFE is not used here since it is not valid any more: by 2035, the average module efficiency will increase and thus the area required by unit capacity installed will be reduced due to technology development.

Generation potentials can also be plotted against installed PV system capacities (Figure 10.14 and Figure 10.15). These figures show that the majority of the annual roof-top based generation is and will be due to small units with capacities below 50 kW_p.

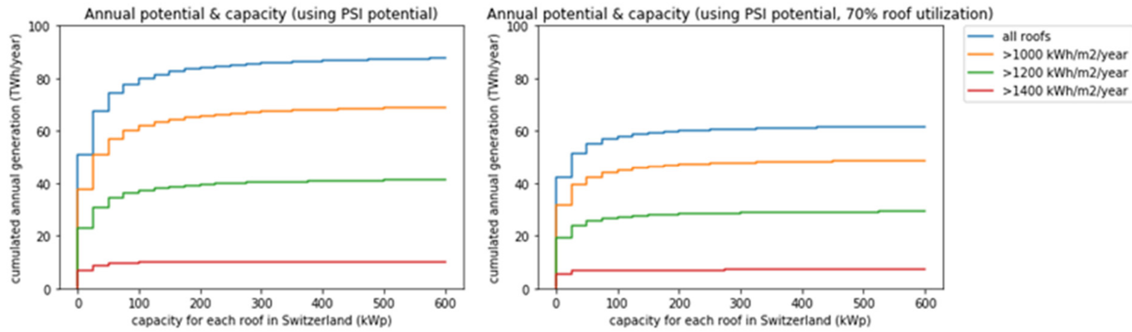


Figure 10.14: Cumulative annual electricity generation potential with roof-top PV panels in Switzerland vs. installed capacities, calculated with current performance parameters. Left: complete coverage of roofs with modules; right: 70% utilization factor. In this calculation, capacities for each roof are split into segments of 25 kW_p. The largest fraction of the generation is due to small PV systems with low capacities – this is shown by the fact that the major part of the generation potential is within the first 25 kW_p segment, meaning that PV systems with capacities below or equal to 25 kW_p can generate around two thirds of the total potential (all roofs, right panel).

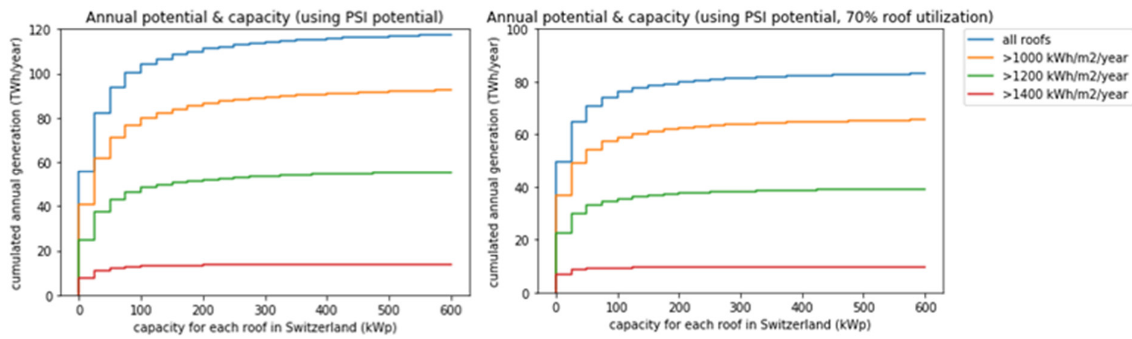


Figure 10.15: Cumulative annual electricity generation potential with roof-top PV panels in Switzerland vs. installed capacities, calculated with performance parameters estimated for year 2035. Left: complete coverage of roofs with modules; right: 70% utilization factor. In this calculation, capacities for each roof are split into segments of 25 kW_p. The largest fraction of the generation is due to small PV systems with low capacities – this is shown by the fact that the major part of the generation potential is within the first 25 kW_p segment, meaning that PV systems with capacities below or equal to 25 kW_p can generate around 60% of the total potential (all roofs, right panel).

Generation potentials vs. LCOE can also be plotted for specific capacity segments of PV systems, similar to the categories used for quantifying LCOE. Figure 10.16 shows these potentials vs. LCOE for specific capacity categories in 2018 (left) and 2035 (right): the largest fraction of the overall generation – both today and in 2035 – can be realized with units with capacities of 10-30 kW_p (green line). The smaller the units are, the higher LCOE.

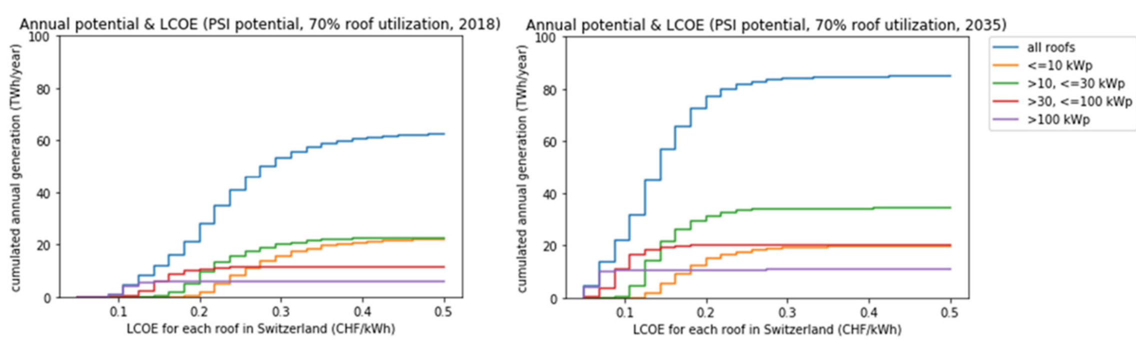


Figure 10.16: Cumulative annual electricity generation potential with roof-top PV panels in Switzerland vs. LCOE for specific capacity categories in 2018 (left) and 2035 (right), with a "roof area utilization factor" of 70%. Units with capacities of 10-30 kW_p contribute most to the overall generation potential.

10.3.3 Limitations and future work

Although the figures of electricity generation potentials vs. LCOEs show the potential that might be achieved at certain LCOE, there are some limitations of this analysis. Special caution needs to be kept in mind when interpreting the results and more in-depth analysis is needed in the future.

1. Potentials as such might be further limited due to social constraints and issues in the electricity supply system, which are out of scope of this analysis. And the assumed "roof utilization factor" of 0.7 should be verified on a large sample of existing roof-top installations.
2. Minor overestimation of LCOE might be introduced by considering all the roofs individually, whereas in reality, multiple roofs that belong to the same owner, such as institutions and companies owning multiple buildings, shall be grouped as one roof for cost consideration. In a future analysis, buildings sharing the same address could be grouped and LCOE for this grouped system should be estimated instead of each individual roof.
3. Minor underestimation of LCOE might be introduced considering the fact that installing PV panels on some buildings in remote areas and on buildings with challenging architecture can be more expensive than assumed in this analysis.
4. Applying system investment costs and average module efficiencies at two reference years only (2018 and 2035) for the entire Switzerland shows the PV generation potential today and in the future with different, reference year specific LCOE. However, it would be more realistic to quantify a time series of generation potentials vs LCOE and explore scenarios of average electricity utility price development as benchmark, which will provide better understanding of the likelihood of annual generation that can be achieved. This means for example, for year x, a corresponding curve of system investment cost can be assumed together with the average module efficiency, area per unit capacity (kW_p), and average electricity utility price. The LCOE for all the roofs in year x can be calculated and compared with the average electricity utility price. If the LCOE of a roof is lower than the average electricity utility price, it indicates a favorable condition to realize its corresponding generation potential, and it will be excluded for future PV installation in the following years (i.e. year x+1, year x+2, etc.).
5. Finally, the potentials shown here represent total yearly generation. PV electricity generation exhibits pronounced daily and seasonal patterns and peaks, which need to be taken into account when using these yearly generation potentials.

11 Natural gas power plants and combined heat and power generation

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11.1 Introduction

Updates in this report for natural gas fueled technologies compared to the previous analysis (Bauer et al. 2017) mainly refer to new data and estimates for current and future natural gas prices, respectively, and new performance data for fuel cells based on recent experience with (large) stationary units.

11.2 Natural gas prices in Switzerland

Current natural gas prices in Switzerland are specific for certain consumer categories, which are determined by the annual gas consumption. These prices have been provided by SFOE (SFOE 2018a) and are used for quantification of current LCOE as well as the basis for projections of future gas prices in Switzerland.

The future development of natural gas prices is quantified based on latest scenarios/projections provided by the International Energy Agency (OECD/IEA 2018), Table 11.1. An increase of natural gas prices for Europe is expected in all three scenarios, in the order of 30-60% until 2040 compared to 2017 prices, indicating large uncertainties, which are mainly policy-driven. Price figures for natural gas imports to Europe have been used as basis for projection of Swiss natural gas prices, taking the average price from January-June 2018 of 6.99 US$/MBtu[46] as current reference price and applying the increase according to the "New Policies" scenario[47] from IEA to the current Swiss prices. Figures for 2050 are based on linear extrapolation, resulting in an increase of 40% compared to 2018. The results of this procedure, i.e. the Swiss natural gas prices used for quantification of current and future LCOE are shown in Table 11.2.

Table 11.1: Fuel prices according to different scenarios from the World Energy Outlook 2018 (OECD/IEA 2018).

				New Policies				Current Policies		Sustainable Development	
Real terms ($2017)	**2000**	**2010**	**2017**	**2025**	**2030**	**2035**	**2040**	**2025**	**2040**	**2025**	**2040**
IEA crude oil ($/barrel)	39	88	52	88	96	105	112	101	137	74	64
Natural gas ($/MBtu)											
United States	6.0	4.9	3.0	3.3	3.8	4.3	4.9	3.4	5.3	3.3	3.6
European Union	3.9	8.4	5.8	7.8	8.2	8.6	9.0	7.9	9.4	7.5	7.7
China	3.6	7.5	6.5	9.2	9.4	9.5	9.8	9.3	10.2	8.3	8.5
Japan	6.6	12.3	8.1	9.8	10.0	10.0	10.1	9.9	10.5	9.0	8.8
Steam coal ($/tonne)											
United States	38	64	60	63	63	64	64	64	69	58	56
European Union	47	103	85	80	83	84	85	84	98	69	66
Japan	45	120	95	85	88	89	90	89	105	74	70
Coastal China	35	130	102	91	93	94	94	95	106	81	79

Political issues with potential impact on Swiss natural gas prices such as the potential liberalization of the Swiss natural gas market have not been taken into account in these extrapolations. However, the LCOE calculations of technologies using natural gas explicitly provide the shares of fuel costs – the impacts of alternative price developments can be easily estimated.

[46] https://ycharts.com/indicators/europe_natural_gas_price (17.11.2018).
[47] This scenario will represent the „baseline" in the upcoming new energy perspectives of SFOE and is therefore also used in this analysis as the reference for future price developments.

Table 11.2: Natural gas prices in Switzerland, used in this analysis. Figures for 2018 are actual prices, while future prices are extrapolated based on scenarios from (IEA 2018). Differentiation between different consumer categories is important in the context of CHP units, which fall into different categories depending on their capacities.

Swiss NG consumer prices [CHF/kWh]									
consumer categories	annual consumption [MWh/a]	2018	2020	2025	2030	2035	2040	2045	2050
II-V	<500	0.0835	0.0863	0.0932	0.0979	0.1027	0.1075	0.1123	0.1171
VI	>500	0.0742	0.0767	0.0828	0.0870	0.0913	0.0955	0.0998	0.1040
VII	>1'163	0.0711	0.0735	0.0793	0.0834	0.0875	0.0915	0.0956	0.0997
VIII	>11'630	0.0636	0.0657	0.0710	0.0746	0.0782	0.0819	0.0855	0.0892
IX	>116'300	0.0503	0.0520	0.0561	0.0590	0.0619	0.0648	0.0676	0.0705
X	>250'000	0.0429	0.0443	0.0479	0.0503	0.0528	0.0552	0.0577	0.0601

11.3 Combined cycle power plants

Technology data for natural gas combined cycle (NGCC) power plants used in the previous report (Bauer et al. 2017) is assumed to be still valid for the present update. As before, LCOE are quantified for NGCC plants without and with CO_2 capture; captured CO_2 could either be permanently stored in suitable geological formations, or further used, e.g. for synthesis of so-called "power-to-gas/liquid" fuels. LCOE do not include any further processing/use of CO_2 after capture at the power plant.

Levelized costs of electricity generation (LCOE) of natural gas combined cycle plants depend strongly on the price of natural gas. The LCOE calculations have been updated using the natural gas prices discussed in section 11.1.

Table 11.3 shows the assumed annual consumption of natural gas in NGCC plants for the different years and the corresponding consumer category according to Table 11.2.

Table 11.3: Annual consumption [MWh/a] of natural gas for NGCC with and without CO_2 capture ("post": post combustion capture; "pre": pre combustion capture).

	MWh/a												Consumer category	annual consumption [MWh/a]
	2018			2020			2035			2050				
scenario	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High		
NGCC	6'250'000	5'084'746	6'557'377	6'048'387	4'918'033	6'349'206	5'952'381	4'838'710	6'153'846	6'250'000	5'084'746	6'557'377	X	>250'000
NGCC post	7'500'000	6'122'449	7'843'137	7'211'538	5'882'353	7'547'170	6'944'444	5'660'377	7'272'727	6'818'182	5'555'556	7'142'857	X	>250'000
NGCC pre	5'909'091	4'839'710	6'159'921	5'571'429	4'543'689	5'831'776	5'416'667	4'415'094	5'672'727	5'318'182	4'333'333	5'571'429	X	>250'000

The large combined cycle power plants are all in consumer category X.

The assumed fuel costs based on the annual consumption are shown in Table 11.4. High and low estimates of LCOE are using the same fuel costs although it should be clear that future gas prices are highly uncertain; the calculated range is due to technology parameters such as power plant efficiencies (Bauer et al. 2017).

Table 11.4: Assumed fuel costs per MWh [CHF/MWh] natural gas (LHV) for NGCC. "Base/Low/High" refers to technology parameters, not to fuel costs – these are independent of the technology development scenario as specified in (Bauer et al. 2017).

	CHF/MWh			
	2018	2020	2035	2050
	Base/Low/High	Base/Low/High	Base/Low/High	Base/Low/High
NGCC	42.9	44.1	54.1	64.0
NGCC post	42.9	44.1	54.1	64.0
NGCC pre	42.9	44.1	54.1	64.0

11.3.1 Current and future electricity generation costs

Table 11.5 shows the results of the LCOE calculations for NGCC plants without any costs associated with CO_2 emissions.

Table 11.5: LCOE of NGCC power plants with and without CO_2 capture ("post": post combustion capture; "pre": pre combustion capture); without CO_2 emission costs.

	Rp./kWh$_{el}$											
	2018			2020			2035			2050		
	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High
NGCC	8.9	8.4	9.8	8.9	8.4	9.7	9.9	9.5	10.7	11.0	10.4	11.7
NGCC post	11.2	10.2	13.0	11.2	10.2	12.8	12.3	11.4	13.7	13.5	12.6	14.8
NGCC pre	11.4	10.5	13.1	11.1	10.2	12.7	12.1	11.4	13.6	13.2	12.5	14.7

In the present calculations, the assumptions regarding load factors are the same as in the previous report (Bauer et al. 2017). It was assumed that a large combined cycle plant in Switzerland would be used in baseload mode, i.e. with high load factor in terms of operational hours per year. Such an operation represents the replacement of nuclear power plants, which are always baseload plants. An average load factor of 7500 (6000 to 8000) hours per year was assumed (Bauer et al. 2017) for the NGCC.

Nevertheless, due to the technical flexibility, NGCC plants in other countries are also used as reserve, i.e. with much lower annual time of operation. In this case, the LCOE figures shown here would not be valid anymore[48]. The LCOE depend strongly on the load factor. For example, the NGCC in Irsching, Germany, is one of the most modern NGCC plants worldwide with high efficiency. Nevertheless, the operating company wants to close down the plant after only few years of operation (Bundesnetzagentur 2018) because the requested annual electricity generation was much lower than expected which implies much higher costs and makes the operation uneconomic for the company under current conditions in Germany (Sebald 2017). Anyways, a low annual load factor (like e.g. 2000 hours per year instead of the assumed 7500 hours per year) would substantially increase the costs per kWh.

11.3.1.1 Costs of CO_2 emissions

It seems likely that potential large NGCC power plants in Switzerland would have to pay for their CO_2 emissions within the European CO_2 market regime.

[48] Apart from LCOE, also other parameters depend on the mode of operation, e.g. power plant efficiency, lifetime and emissions.

The price of European CO_2 emission allowances has been steadily growing over the last 12 months (Figure 11.1) and is currently[49] at a level of 20.3 €/tCO_2.[50] This corresponds to 22.9 CHF/tCO_2 at the current exchange rate of 1.13 CHF/€[51].

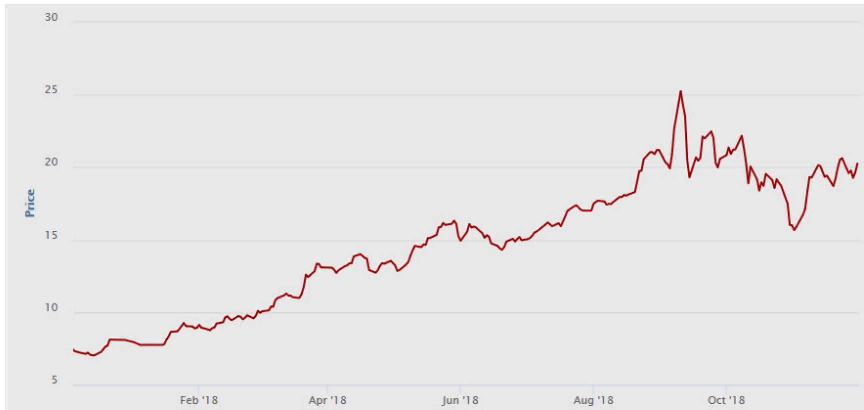

Figure 11.1: Development of the European CO_2 emission allowance price [€/tCO_2] over the last 12 months.[52]

Future CO_2 prices are at least as uncertain as fossil fuel prices. The World Energy Outlook 2018 provides estimates for future CO_2 prices, which are used in this analysis; consistently with natural gas prices according to the "New Policies" scenario. (OECD/IEA 2018) projects future CO_2 prices of 25 and 43 €/tonCO_2 in 2025 and 2040, respectively, for the European Union. CO_2 prices for potential NGCC power plants in Switzerland in 2035 and 2050 are linearly inter- and extrapolated based on these figures[53] and listed in Table 11.7. An increase by a factor of 2.3 is projected until 2050.

Table 11.6 shows direct CO_2 emissions of NGCC plants with baseline technology parameters. Emissions will go down in the future due to increasing power plant efficiencies.

Table 11.6: Direct CO_2 emissions of NGCC power plants with and without CO_2 capture ("post": post combustion capture; "pre": pre combustion capture), according to table 15.18 in (Bauer et al. 2017), best estimates ("base" values).

direct CO_2 emissions, NGCC [g/kWh]				
	2018	2020	2035	2050
NGCC	348	336	325	320
NGCC, post	48	47	41	37
NGCC, pre	41	38	37	37

Table 11.7 shows the resulting costs of direct NGCC power plant CO_2 emissions, calculated with the current and future European CO_2 emission allowance prices based on (OECD/IEA 2018). The increasing CO_2 prices more than compensate decreasing CO_2 emissions resulting in about an overall doubling of CO_2 emission costs for NGCC power plants in Switzerland until 2050.

[49] 30.11.2018 .
[50] Source: https://www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#!/2018/11/30 (2.12.2018).
[51] https://www.xe.com/currencyconverter/convert/?Amount=1&From=CHF&To=EUR (2.12.2018).
[52] https://www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#!/2018/11/30 (2.12.2018).
[53] Using current exchange rates of 1.18 $/€ and 1.13 CHF/€.

Table 11.7: Costs associated with direct NGCC power plant CO_2 emissions, calculated based on the current European CO_2 emission allowance price of 20.3 €/tCO_2 for 2018 and future CO_2 prices extrapolated based on future CO_2 prices from (OECD/IEA 2018); ("post": post combustion capture; "pre": pre combustion capture).

CO_2 emission costs [Rp/kWh]				
	2018	2020	2035	2050
CO_2 price [CHF/tCO_2]	22.9	23.2	35.5	52.8
NGCC	0.80	0.78	1.16	1.69
NGCC, post	0.11	0.11	0.15	0.20
NGCC, pre	0.09	0.09	0.13	0.20

11.3.1.2 LCOE of NGCC with costs of CO_2 emissions

Table 11.8 the shows the results of the LCOE calculations for natural gas combined cycle plants including costs of CO_2 emissions as specified above.

Table 11.8: LCOE including CO_2 emission costs for NGCC power plants with and without CO_2 capture ("post": post combustion capture; "pre": pre combustion capture).

	Rp./kWh$_{el}$											
	2018			2020			2035			2050		
	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High
NGCC	9.7	9.2	10.6	9.6	9.1	10.5	11.1	10.6	11.8	12.6	12.0	13.4
NGCC post	11.4	10.3	13.1	11.3	10.3	12.9	12.5	11.5	13.9	13.7	12.7	15.1
NGCC pre	11.5	10.6	13.2	11.2	10.3	12.8	12.3	11.5	13.8	13.4	12.6	14.9

11.4 Combined heat and power (CHP) generation units

Technology data for combined heat and power plants used in the previous report (Bauer et al. 2017) have been based on the extensive ASUE list (ASUE 2014). As of Nov 2018, this is still the most recent ASUE list. The technical data is assumed to be still valid for the present update.

Costs of electricity generation of natural gas combined heat and power generation units depend strongly on the price of natural gas. The LCOE calculations have been updated using the natural gas prices discussed in section 11.1.

Table 11.9 shows the assumed annual consumption of natural gas for the different years and the corresponding consumer category according to Table 11.2.

Table 11.9: Annual consumption of natural gas for combined heat and power generation units.

	MWh/a												Consumer category	annual consumption [MWh/a]
	2018			2020			2035			2050				
	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High		
CHP 1kWe	3	2	3	3	2	3	3	2	3	3	2	3	II-V	<500
CHP 10kWe	27	19	35	27	19	35	27	19	35	27	19	35	II-V	<500
CHP 100kWe	346	295	399	346	295	399	346	295	399	346	295	399	II-V	<500
CHP 1000kWe	4'658	4'272	5'308	4'658	4'272	5'308	4'658	4'272	5'308	4'658	4'272	5'308	VII	>1'163

The fuel costs based on the annual consumption of the different CHP plant types are shown in Table 11.10. High and low estimates are using the same fuel costs although it should be clear that future gas prices are highly uncertain; the ranges are due to the assumed ranges for technology parameters such as efficiencies (Bauer et al. 2017).

Table 11.10: Fuel costs per MWh natural gas (LHV) for CHP. "Base/Low/High" refers to technology parameters, not to fuel costs – these are independent of the technology development scenario as specified in (Bauer et al. 2017).

	CHF/MWh			
	2018	2020	2035	2050
	Base/Low/High	Base/Low/High	Base/Low/High	Base/Low/High
CHP 1kWe	83.5	86.3	102.7	117.1
CHP 10kWe	83.5	86.3	102.7	117.1
CHP 100kWe	83.5	86.3	102.7	117.1
CHP 1000kWe	71.1	73.5	87.5	99.7

11.4.1 Current and future electricity generation costs

Table 11.11 shows the results of the LCOE calculations with heat credits for the combined heat and power plants. As in the previous analysis (Bauer et al. 2017), heat credits were calculated using the costs of "saved" natural gas in a conventional natural gas boiler as reference heating system.

Table 11.11: LCOE for CHP units with heat credits.

	Rp./kWh$_{el}$											
	2018			2020			2035			2050		
	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High
CHP 1kWe	71.7	50.0	114.3	70.3	49.2	111.9	67.2	47.5	106.2	66.0	47.2	103.7
CHP 10kWe	29.4	22.0	45.0	29.2	21.8	45.2	29.6	22.7	45.0	30.5	23.8	45.8
CHP 100kWe	20.0	14.6	25.6	20.1	14.1	26.3	21.8	15.5	28.0	23.6	16.9	29.9
CHP 1000kWe	15.6	13.2	18.3	15.7	13.2	18.8	17.3	14.8	20.4	19.1	16.4	22.3

Table 11.12 shows the results of the LCOE calculations without heat credits for the combined heat and power plants.

Table 11.12: LCOE for CHP units without heat credits.

	Rp./kWh$_{el}$											
	2018			2020			2035			2050		
	Base	Low	High	Base	Low	High	Base	Low	High	Base	Low	High
CHP 1kWe	92.5	72.0	130.8	91.4	71.4	128.6	90.7	72.3	124.8	91.7	74.2	124.0
CHP 10kWe	48.2	39.7	62.6	48.1	39.8	62.3	50.7	42.7	64.1	53.5	45.6	66.7
CHP 100kWe	29.6	26.1	34.4	29.7	26.3	34.4	32.2	28.7	36.8	34.9	31.3	39.5
CHP 1000kWe	20.8	19.0	23.1	20.9	19.1	23.1	22.7	20.9	25.0	25.0	23.1	27.3

11.5 Fuel cells

11.5.1 Performance parameters

The main change since the release of the original report (Bauer et al. 2017) is that the final report for the European ENE field project has now been released (ene.Field 2017), providing some additional information. PEFC and SOFC efficiencies for residential applications were updated based on measured values collected in this project. This resulted in a slight decrease for PEFC and slight increase for SOFC electrical efficiencies and slight increases in system CHP efficiency for both technologies.

The optimistic lifetime for residential PEM fuel cells has been increased based on new reports from Panasonic (E4tech 2017).

Costs for residential fuel cell CHP systems have been updated based on (Wei at al. 2017), who present a cost breakdown for fuel cell systems installed in USA and Japan from 2009-2014, and E4tech's fuel cell industry review 2017 (E4tech, 2017). The expected capital cost in 2035 for residential systems were also decreased based on the above-mentioned reports. Capital cost assumptions for 2050 were not changed. Further information regarding Japanese ENE Farm costs (especially the conclusion that system costs have stagnated since 2015) can be found in (Ozawa and Kudoh 2018).

There are almost no changes for larger systems. The exception is a decrease in capital costs for current and near-future 300 kW SOFC systems. This cost decrease is based on financial reports from (Bloom energy 2018) that claim sales prices for their 100 kW SOFC systems of roughly 6500 USD/kW. Furthermore, a report was released by the (U.S. Energy Information Administration 2017) that reports costs on fuel cell CHP systems that were also considered while making these adjustments. Table 11.13 shows the list of fuel cell performance parameters, with updated values for 2018 shown in red.

The updated results also reflect the updated natural gas prices as described in Table 11.2. Residential systems are assumed to be in consumer category II-V, while the larger 300 kW systems are assumed to be in category VII. No changes in the assumptions regarding the surcharge for biomethane are made compared to the original report (Bauer et al. 2017) where biomethane prices are calculated with a 0.075 CHF/kWh surcharge based on the prices of Energie360, a gas provider in Zurich (Energie360 2016).

These modifications of performance parameters show an impact on both electricity generation costs and environmental burdens. However, the impact on life-cycle GHG emissions is minor and new results are therefore not discussed. However, updated life-cycle GHG emissions are provided in the fuel cell fact sheet (section 3).

Table 11.13: Fuel cell system performance indicators, updated values for 2018 shown in red. Cost values are for European installations. Changes for 2018 shown in red based on: E4tech, 2017, ene.Field, 2017, U.S. Energy Information Administration, 2017, Wei et al., 2017, Bloom energy, 2018, Ozawa and Kudoh, 2018.

			PEFC			SOFC			SOFC			MCFC			PAFC		
			Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.	Cons.	Base	Opt.
Electrical Capacity	kW		1	1	1	1	1	1	300	300	300	300	300	300	300	300	300
Electrical Efficiency	LHV	2018	28%	32%	35%	28%	42%	47%	48%	51%	54%	39%	42%	45%	35%	38%	41%
		2020	32%	36%	39%	35%	44%	48%	52%	55%	58%	41%	44%	47%	37%	40%	43%
		2035	39%	42%	45%	42%	45%	60%	60%	63%	66%	52%	55%	58%	39%	42%	45%
		2050	42%	45%	50%	47%	50%	60%	62%	65%	68%	57%	60%	63%	42%	45%	48%
CHP Efficiency	LHV	2018	85%	87%	90%	80%	85%	95%	70%	80%	90%	70%	80%	90%	70%	80%	90%
		2020	85%	88%	95%	85%	88%	95%	75%	85%	92%	75%	85%	92%	75%	85%	92%
		2035	85%	89%	95%	85%	89%	95%	78%	88%	93%	78%	88%	93%	78%	88%	93%
		2050	85%	90%	95%	85%	90%	95%	80%	90%	95%	80%	90%	95%	80%	90%	95%
Heat Temperature	°C	2018	40	50	70	80	80	80	80	80	500	80	80	500	80	80	120
		2020	50	60	80	80	80	80	80	80	500	80	80	500	80	80	120
		2035	60	70	80	80	80	80	80	80	200	80	80	200	80	80	120
		2050	70	80	80	80	80	80	80	80	200	80	80	200	80	80	120
System Lifetime	years	2018	10	11	18	10	11	13	10	11	13	10	10	13	18	20	26
		2020	11	13	20	11	15	20	11	15	20	10	13	16	18	23	29
		2035	13	15	23	14	20	26	14	20	26	11	15	20	19	28	30
		2050	14	20	26	16	23	29	16	23	29	14	20	26	23	30	30
Stack Lifetime	thousand hours	2018	40	45	70	40	45	52	40	45	52	40	40	52	70	80	104
		2020	45	50	80	42	60	78	42	60	78	40	50	65	63	90	117
		2035	50	60	90	56	80	104	56	80	104	42	60	78	77	110	120
		2050	56	80	104	63	90	117	63	90	117	56	80	104	91	120	120
Capital Costs	CHF/kW	2018	25000	20000	15000	25000	20000	15000	15000	10000	7000	6000	4000	3200	9000	6000	4800
		2020	24000	16000	10000	24000	16000	10000	14000	9000	7000	5700	3800	3040	7500	5000	4000
		2035	10000	7000	4000	10000	7000	4000	10000	4000	3200	6000	4000	3200	4500	3000	2400
		2050	10000	4000	2000	10000	4000	2000	4500	3000	2400	4500	3000	2400	4000	2500	2000
O&M Costs	CHF/kW	2018	500	400	300	500	400	300	120	100	70	120	100	70	120	100	70
		2020	400	300	200	400	300	200	100	70	45	100	70	45	100	70	45
		2035	300	250	200	300	250	200	70	45	45	70	45	45	70	45	45
		2050	250	200	200	250	200	200	70	45	45	70	45	45	70	45	45
Operating hours per year		all	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000

11.5.2 Electricity generation costs

Updated fuel cell performance parameters as well as new natural gas prices (section 11.1) are used to quantify current and future LCOE.

Figure 11.2 and Figure 11.3 show levelized cost of electricity for electricity generation from fuel cells for methane (natural gas) and biomethane as fuels, respectively. The bar chart shows the cost of electricity without considering any value of the heat produced with base case parameters, while the net cost and range values (using conservative and optimistic parameter values, respectively) consider a heat credit equal to the value of the fuel used. The methodology for calculating the heat credit remains the same as in the original report: as the heat is assumed to displace the use of a natural gas boiler (with an efficiency of 100%), the heat produced by the fuel cells is credited with a value equal to the price of natural gas or biomethane (equivalent to the amount of heat generated with this fuel).

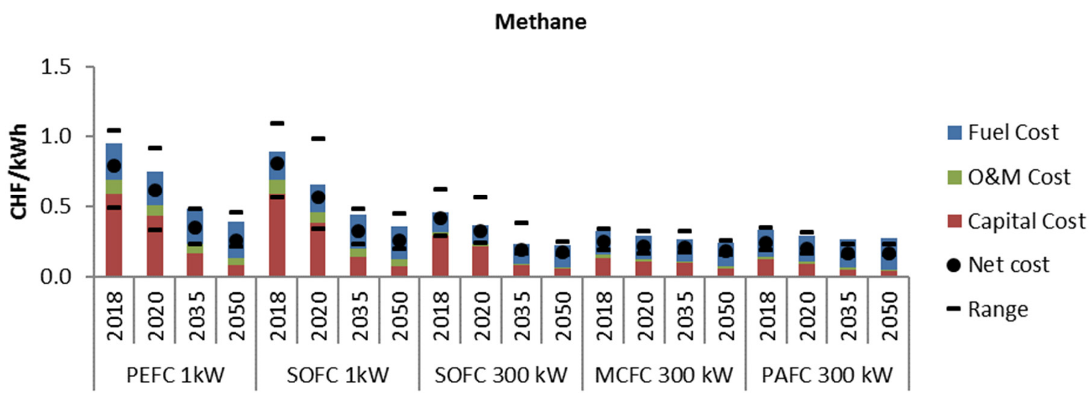

Figure 11.2: Electricity generation costs from combined heat and power fuel cell systems powered by natural gas in Switzerland until 2050.

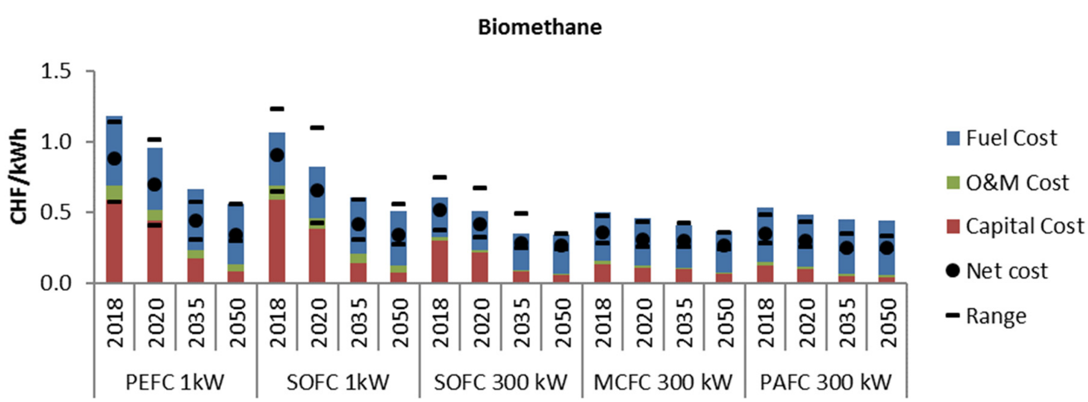

Figure 11.3: Electricity generation costs from combined heat and power fuel cell systems powered by biomethane in Switzerland until 2050.

12 Other technologies: electricity from biomass, coal power, wave and tidal power, deep geothermal power, concentrated solar thermal power, nuclear power

Electricity generation costs and generation potentials have not been updated for these technologies – potentials and LCOE previously calculated and documented in (Bauer et al. 2017) are assumed to be still valid; the fact sheets remain identical.

13 Environmental burdens

For the sake of completeness, life cycle based environmental burdens of electricity generation are provided here (per kWh electricity generated). These figures are identical to those in (Bauer et al. 2017) – details regarding data sources and methodology for quantification can be found there.

Table 13.1 shows absolute burdens, Figure 13.1 shows the relative technology performance for the same impact categories.

Table 13.1: Life cycle environmental burdens of different electricity generation technologies per kWh electricity generated, ILCD 2011 Midpoint+ V1.09 / EU27 2010, equal weighting, ecoinvent v3.3, system model "allocation, cut-off by classification" (Bauer et al. 2017). PTA: point absorber; CC: combined cycle; LHP: large hydropower; PWR: pressurized water reactor; BWR: boiling water reactor.

Impact category	Unit	Wave power: PTA	NG CHP	Swiss consumption mix	Biogas CHP	Wood CHP	Hard coal power plant	NG CC power plant	Geothermal (EGS)	LHP: reservoir	LHP: run-of-river	Lignite power plant	Nuclear: PWR	PV, roof-top, multi-c Si	Wind onshore	Wind offshore	Nuclear, BWR
Climate change	kg CO2 eq	1.04E-01	6.51E-01	9.66E-02	2.38E-01	2.31E-01	1.05E+00	4.37E-01	7.74E-02	6.82E-03	4.24E-03	1.22E+00	1.20E-02	7.46E-02	1.70E-02	1.49E-02	1.27E-02
Ozone depletion	kg CFC-11 eq	4.22E-09	8.05E-08	6.26E-08	6.61E-09	9.23E-08	2.33E-09	7.79E-08	3.83E-09	4.04E-10	3.17E-10	2.68E-09	1.04E-07	1.30E-08	1.19E-09	8.20E-10	1.07E-07
Human toxicity, non-cancer effects	CTUh	2.52E-08	1.65E-08	3.32E-08	1.28E-08	4.19E-07	1.02E-07	1.13E-08	2.18E-08	2.12E-09	2.02E-09	5.40E-07	2.78E-08	1.02E-07	2.14E-08	1.73E-08	2.95E-08
Human toxicity, cancer effects	CTUh	7.71E-10	5.83E-09	6.60E-09	2.03E-09	6.22E-09	2.24E-08	3.89E-09	1.12E-08	1.19E-09	1.29E-09	1.82E-07	2.65E-09	9.61E-09	9.47E-09	7.44E-09	2.77E-09
Particulate matter	kg PM2.5 eq	8.10E-05	8.67E-05	2.85E-05	1.41E-04	3.13E-04	7.49E-05	5.67E-05	8.31E-05	6.55E-06	5.03E-06	9.58E-05	2.10E-05	8.31E-05	1.96E-05	1.60E-05	2.22E-05
Ionizing radiation HH	kBq U235 eq	2.12E-02	9.44E-03	4.54E-01	2.11E-02	4.28E-03	7.00E-03	8.99E-03	9.20E-03	3.97E-04	2.57E-04	6.99E-03	7.26E-01	7.31E-03	1.08E-03	7.60E-04	1.19E+00
Photochemical ozone formation	kg NMVOC eq	3.54E-04	1.29E-03	1.50E-04	7.91E-04	1.72E-03	7.84E-04	5.29E-04	2.23E-04	2.28E-05	1.91E-05	9.58E-04	4.81E-05	2.91E-04	7.55E-05	5.70E-05	5.07E-05
Acidification	molc H+ eq	1.58E-03	1.40E-03	2.54E-04	5.54E-03	1.99E-03	1.51E-03	7.13E-04	4.66E-04	3.02E-05	2.27E-05	1.94E-03	7.87E-05	6.26E-04	1.21E-04	1.06E-04	8.28E-05
Terrestrial eutrophication	molc N eq	1.29E-03	3.22E-03	5.44E-04	2.32E-02	9.63E-03	2.92E-03	1.25E-03	7.45E-04	8.08E-05	6.55E-05	3.75E-03	1.71E-04	8.26E-04	2.19E-04	1.72E-04	1.81E-04
Freshwater eutrophication	kg P eq	3.83E-07	3.13E-05	6.79E-05	1.13E-05	4.69E-05	1.51E-04	2.48E-05	4.15E-05	1.73E-06	1.55E-06	2.92E-03	8.21E-06	7.50E-05	1.30E-05	1.04E-05	8.73E-06
Marine eutrophication	kg N eq	2.51E-05	3.00E-04	8.03E-05	3.84E-04	5.71E-04	2.94E-04	1.19E-04	7.37E-05	7.40E-06	6.03E-06	9.34E-04	5.64E-05	9.44E-05	2.23E-05	1.89E-05	5.98E-05
Freshwater ecotoxicity	CTUe	1.15E-01	4.81E-01	6.48E-01	2.78E-01	8.28E-01	1.83E+00	3.29E-01	6.70E-01	5.55E-02	6.40E-02	1.71E+01	3.36E-01	7.76E+00	7.11E-01	1.00E+00	3.55E-01
Land use	kg C deficit	no data	3.98E-01	1.02E-01	8.72E-02	3.87E+00	3.67E-01	2.79E-01	1.97E-01	-2.44E-02	9.17E-03	1.05E-02	1.80E-02	9.56E-02	1.85E-01	2.14E-02	1.90E-02

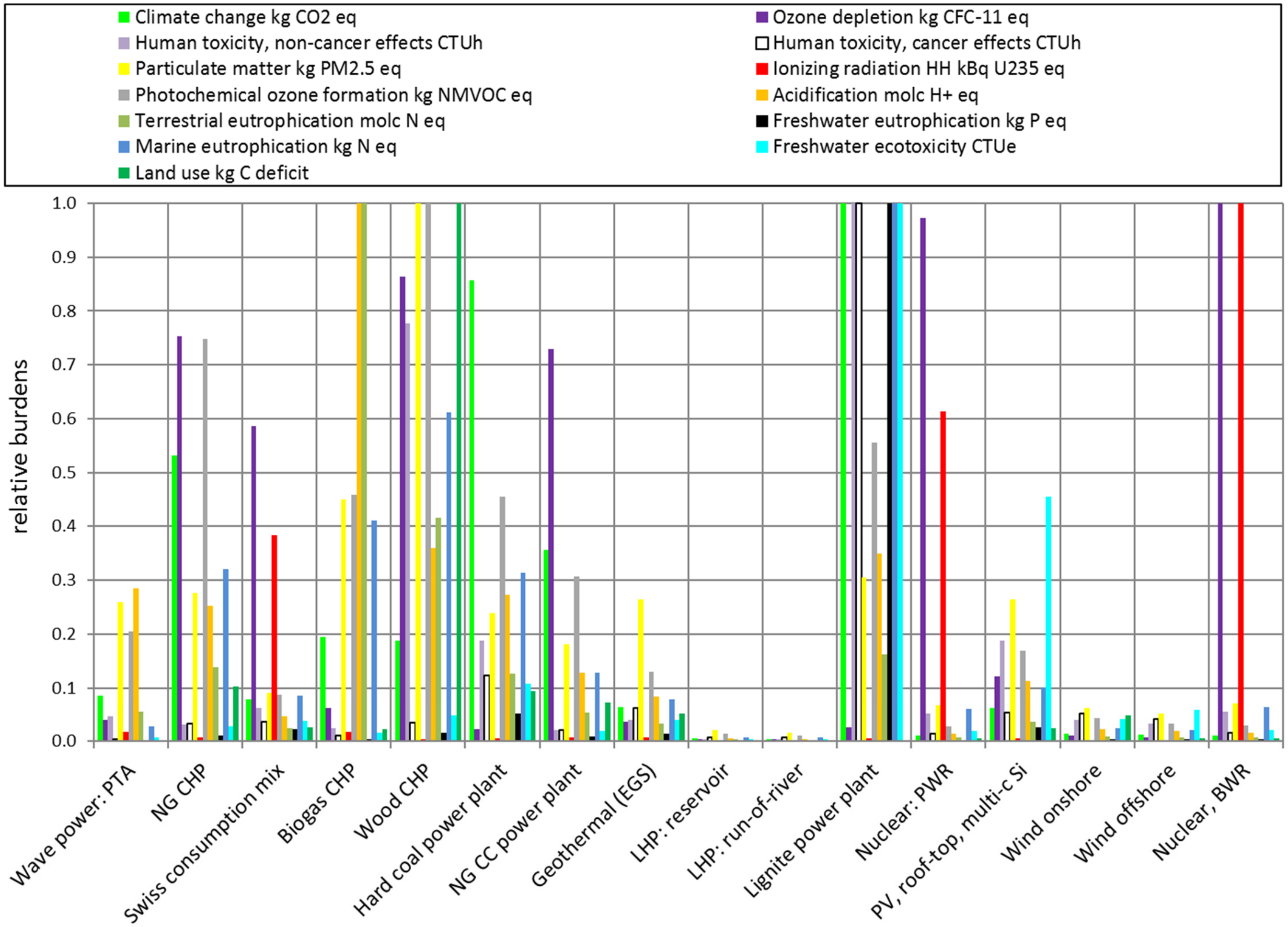

Figure 13.1: Relative life cycle environmental burdens of different electricity generation technologies, ILCD 2011 Midpoint+ V1.09 / EU27 2010, equal weighting, ecoinvent v3.3, system model "allocation, cut-off by classification" (Bauer et al. 2017). PTA: point absorber; CC: combined cycle; LHP: large hydropower; PWR: pressurized water reactor; BWR: boiling water reactor.

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