Flexible capacity addition case study at reduced grid tariff without security of supply

Vincent Layec
Institute for Information Systems
University of Applied Sciences and Arts Northwestern Switzerland, FHNW
4600 Olten, Switzerland
Email: vincent.layec@fhnw.ch

Holger Wache
Institute for Information Systems
FHNW
4600 Olten, Switzerland
Email: holger.wache@fhnw.ch

***Abstract*—Energy intensive industries are sensitive both to the reliability and to the costs of their energy supply system. With renewable energy becoming more affordable, their weather dependent over- and under production will cause more volatile and higher spot price, but fees prevent the roll-out of Power-to-Gas. In this paper, we differentiate the new flexible loads of energy conversion and storage like Power-to-X or batteries from the regular loads of the core activity of industries and we design the tariff system of flexible loads in such a way to be financially attractive, by abandoning a security of supply that they actually do not need. In a previous work, the technical functionality of a load management system solving the grid congestion issues was described. Here we aggregate the yearly energy balance and the associated costs in six case studies to verify that the roll-out of the new flexible loads is economically viable. The financial attractiveness of the roll-out of new flexible loads with reduced tariff system and future drop in technology price is verified in all these customers and the tariff reduction for conditional loads is the decisive factor of the profitability in four of them.**

***Index Terms*—power grid capacity, security of supply, smart grid, flexible loads, power tariff**

I. Introduction

The reduction of greenhouse gas emissions under cost constraints represents a difficult challenge for industries. The switch from the conventional mix of electricity to a renewable mix can solve unfortunately only half of the problem. Indeed, besides their consumption of electricity, many branches of industry rely on a consumption onsite of fossil fuels like natural gas from the grid or off-grid supply of heating oil or gas. Addressing the onsite fossil fuels consumption is a major next step for industries already supplied with renewable electricity, but this change of onsite consumption can be expensive. Dissuasion with energy prices would only moves the problem abroad and end consumers will continue to buy (with imports) products of energy intensive industries. This dissuasion would create a carbon leakage and it is not adequate. An alternative is a substitution of the fossil fuel consumption of industries with local Power-to-X (PtX) units, i.e. Power-to-Gas (PtG) or Power-to-Heat (PtH). Opponents counter that the connection of new PtX units locally would provoke a congestion in power grids with limited capacity and the required grid reinforcement would be more expensive than the business as usual approach with continuation of use of both grids of electricity and gas for their remaining lifetime. We investigate here why the scenario of massive roll-out until a congestion is economically possible and why a load management system is required to avoid a grid reinforcement.

978-1-7281-1257-2/19/$31.00©2019 IEEE

II. State of the art

The security of energy supply of industrial end-customers is essential to prevent expensive production loss or physical damages in case of an interruption. The willingness of industries to install own fossil fuels generators in countries without systematic redundant grids attests the value of the security of supply. In some distribution system operators (DSO) in USA, Italy or France, demand response programs [1] have been tested to reduce peak loads in power grids by giving financial incentives to customers to modify their consumption pattern. They include the peak time rebate (PTR) with monetary reward to customers reducing their load at certain hours, and inclining block rates (IBR) with increasing tariff depending on the current power level (1 kWh is more expensive e.g. between 9 and 10 kW than between 0 and 1 kW). The current practice in our investigated case studies in Germany and Switzerland is a supply with at least one redundancy in the power grid. DSOs reinforce the power grid as soon as capacity additions are planned in their customers. This practice improves possibilities to plan civil works in the infrastructure in the long term and is supported by the low costs of materials (power lines, transformer) compared to the work force required in case of frequent failures and black out. Therefore, the technical association of DSO recommends the fulfilment of a redundant security of supply and the associated grid reinforcements. As the costs of the infrastructure is easier to transfer into the fee of grid usage than work force, there is no incentive for planers in DSO to deviate from this state of art best practice.

III. Capacity addition without security of supply

Current electrical grids are not used at their full capacity potential. Half of the power capacity is kept in reserve to guarantee the supply of neighbouring customers in case of a failure in one element of their branch of the grid, a so-called N-1 case. The full grid capacity is only used on rare days. The authors of [3] investigated how a load management system enables this utilization without endangering the N-1 security of supply of regular consumers. For this purpose, they introduced a new category of loads with the special property of abandoning the security of supply, called conditional loads, whereas all other loads remaining in the existing system are called unconditional loads. A planning on day-head basis with the possibility for an automatic system of DSO to curtail load schedules in case of excess power enables a safe operation of the grid, respecting the operational constraints of the customer and with almost optimal energy costs for customers. For technical validation purposes, they assumed a large roll-out of new flexible loads and run many daily simulations to check that the capacity limitations of the power grid are fulfilled in case of congestion [4]. The left out economic aspects of the costs and revenues of this roll-out are the object of the current analysis.

IV. Validation Settings

We describe six case studies with real data of consumption from pilot customer and with assumed new consumption capacities in order to generate a scenario with grid congestion. We compare the profitability of the new loads in a reference scenario with standard tariff (STT) of electricity and in a new scenario with reduced Flexible Tariff (FT, called PAT in [4]). We aim to verify that the roll-out of the flexible loads will be financially possible for industrial customers and to quantify the particular contribution of the FT in this profitability.

A. Compared Scenarios

We analyse the situation of industrial customers of the middle voltage level in four main scenarios of Table I. Battery and PtG are potential drivers of a grid congestion, but they are too expensive today. Therefore, we select a situation in the future, e.g. 2035, when they will be mature and affordable. Many electricity tariffs are today constant with the time and we expect in the future more often variable tariffs, like Real Time Tariff, announced on day-ahead base (DA-RTP). If many energy customers use automatic schedulers to minimize energy costs based on spot price, these tariffs could increase the simultaneity of consumption [2] and thus the risks of congestion. The reference scenario 2 is `2_future_noLoad_noFT`, with higher energy costs and more volatile than in `1_today_noLoad_noFT`. With an aggregation of daily simulation results into yearly balance, we quantify whether the transition from scenario 2 to `4_future_Load_FT` is financially attractive and possible at all. Then we repeat it for the transition from scenario 2 to `3_future_Load_noFT` to determine in which case there were financial barriers to the investments into the new loads in absence of the concept of conditional loads and of FT.

B. Assumptions of energy price

The energy price of electricity follows a spot price, known on day-ahead basis. The spot price 2035 is predicted based on a European unit commitment model. The average at 61 EUR/MWh is twice higher than the records of 2016 at 30 EUR/MWh (this increase already happened within 3 years from 2016 to 2019 so it is realistic). It is also more volatile: the mean difference between daily highest price and daily lowest price will be at 52 EUR/MWh so 2.3 times higher than 2016 at 23 EUR/MWh. New conditional loads (i.e without guarantee of supply) on the right column of Table II will have a reduced power component of the grid price of only 10 EUR/kW/a. The energy component of the grid price, the taxes and the fees will be reduced from 10 ct/kWh in the Standard Tariff (STT) of unconditional loads to 4.8 ct/kWh in the Flexible Tariff (FT) of conditional loads. On one side, the DSO will give a reduced grid price for the middle voltage usage, and on the other side, as this reduction is not sufficient, we assume that the energy market regulatory body would grant additional reductions on taxes and fees. The gas price 2035 is assumed to be 8 ct/kWh, including all fees and taxes.

TABLE I
MAIN SCENARIOS

name	year of energy price	new loads	reduced FT
`1_today_noLoad_noFT`	2016	no	no
`2_future_noLoad_noFT`	2035	no	no
`3_future_Load_noFT`	2035	yes	no
`4_future_Load_FT`	2035	yes	yes

TABLE II
ELECTRICITY TARIFFS

tariff for	component	STT 2035	FT 2035
energy (ct/kWh)	spot (mean value)	6.1	6.1
	middle voltage grid	3.0	0.3
	transmission grid	2.0	2.0
	taxes and fees	5.0	2.5
power (EUR/kW/a)	grid	100.0	10.0

C. Assumptions of future investment costs

We investigate the installation of new units of energy production, conversion and storage according to specific costs (EUR/kW) of Table III derived from [5] and [6].

TABLE III
ASSUMED SPECIFIC TECHNOLOGY COSTS (EUR/KW) AND LIFETIME (A)

-	specific costs (EUR/kW)		lifetime
technology	today	in future	a
photovoltaic (PV)	1,000	500	20
battery	1,000	200	10
electrolyser (PtG)	5,000	900	10
electrical boiler (PtH)	100	40	20
heat pump	3,000	2,000	20

The estimated costs are specific i.e. per power capacity. Economies of scales usually lowering specific costs of large units are neglected. The cost of heat pump is meant per electric power, which is lower than the thermal power due to the coefficient of power, assumed to be 4. We assume the efficiency of the PtH equal to the efficiency of the substituted fossil fuel boiler, and the efficiency of PtG to 75 %, so 6 ct of fossil fuel consumption is avoided per kWh of electricity converted by the electrolyser. Another particularity is the electric battery,

TABLE IV
OVERVIEW OF THE SIX CUSTOMERS AND ENERGY CHARACTERISTICS BEFORE NEW LOADS

customer activity location	Customer A food Germany	Customer B machinery Germany	Customer C food Germany	Customer E machinery Switzerland	Customer F machinery Switzerland	Customer G residential Switzerland
electricity power value (kW)	1,800	225	3,800	500	2,000	150
electricity consumption (MWh/a)	9,284	662	16,883	2,585	7,543	487
fossil energy type	gas	gas (off-grid)	gas	gas	gas	heating oil
applicable fossil energy demand (MWh/a)	20,000	300	16,000	1,020	872	600
PV (kW)	300	437	-	-	-	-

TABLE V
SIMULATION SETTINGS (KW) IN SIX CUSTOMERS AND AMORTISATION

settings (kW)	Cust. A	Cust. B	Customer C	Cust. E	Customer F	Customer G
PV before FT	300	437	-	-	-	-
PV with FT	1,500	700	400	500	1,000	150
PtH with FT	500	-	-	100	-	3x25 as heat pumps
PtG with FT	-	100	-	100	1,000	-
Battery with FT	-	100	-	-	-	-
Reallocation of STT to FT	-	-	4x250 (cooling machines)	-	2x(450+200) (ovens)	-
yearly static amortisation (EUR/a)	31,000	17,575	10,000	21,700	115,000	11,250

TABLE VI
YEARLY ENERGY BALANCE (MWH/A)

Customers	Customer A	Customer B	Customer C	Customer E	Customer F	Customer G
STT import before FT	10,420	163	16,934	2,585	7,543	487
STT import with FT	9,184	92	15,520	2,090	3,472	345
other energy import before FT	20,000	300	16,000	1,020	872	600
other energy import with FT	19,696	-81	16,000	907	612	0
FT import with FT	400	137	255	134	3,637	150

which is not only characterised by its power capacity (kW), but also by its energy storage capacity (kWh). We consider only the particular case of batteries with a ratio of 1 kWh storage capacity per kW power capacity. We consider that the specific prices for year 2035 will drop compared to 2016 more in new products like PtG that in mature technologies (PV or heat pumps). For the evaluation of changes in yearly energy costs, a static amortization (without interests) is counted over 20 years. In technologies with a shorter lifetime of e.g. 10 years, a reinvestment is considered.

D. Current setting of customers and roll-out of new loads

Table IV displays the characteristics of the six customers and their energy use. The row of fossil energy consumption includes consumption for heating or for process purposes. This applicable consumption is calculated from todays consumption, but reduced in customers A, C, F and G thanks to the expected installation of a new waste heat recovery (WHR).

We assume for customer A in Table V an extension of PV panels of 1200 kW from 300 to 1500 kW for 600,000 EUR and a PtH unit of 500 kW for 20,000 EUR which leads to a total amortization of 31,000 EUR / a over a 20 years period. The extension of PV panels of 263 kW in customer B from 437 to 700 kW goes along with a new battery of 100 kW and 100 kWh for and a PtG unit of 100 kW. In C a new PV panel of 400 kW is installed. Four existing cooling machines of 250 kW in reserve and connectable so far as unconditional loads. They will be connected instead as conditional loads. For E, we assume a new PV panel of 500 kW, and PtH and PtG of 100 kW each. For F, we set a new PV panel of 1000 kW, and PtG of 1000 kW. F has an existing PtH in four ovens of 500, 500, 250 and 250 kW as unconditional load to melt metal. In each oven, 50 kW must remain unconditional load in order to protect the facility in the N-1 case by maintaining the metal warm. The other 1300 kW of ovens will be reallocated to conditional load instead. For G, we assume a new PV panel of 150 kW, and three heat pumps of each 25 kW_{el}.

V. RESULTS

A. Yearly Energy results

Table VI summarizes the yearly aggregated daily simulation results before FT (Scenario 1 or 2) and with FT (Scenario 4). The main observations in these disparate results are: the import of fossil fuels is completely substituted in customers B and G but unchanged in C (that has - like also A and F - potentials for WHR outside of the concept of conditional loads). The share of electricity at FT for conditional loads is large in customers B and F, but small for A and C.

B. Yearly Energy Costs

Table VII displays the aggregated results of energy costs and their change between scenario 2 and 4. Particularities are:

- the change of the energy component of the electrical cost results of the combination of many factors (decrease by substitution of STT by PV or by FT, increase by over

TABLE VII
YEARLY ENERGY COSTS (EUR/A OR % OF CHANGE)

Customers	Customer A	Customer B	Customer C	Customer E	Customer F	Customer G
FT change in energy electric cost	-11.1 %	+40.2 %	-4.4 %	+15 %	-24.0 %	-7.8 %
FT change in power electric cost	+2.8 %	+18 %	+2.6 %	+4.0 %	-54 %	+5.0 %
FT change in fossil energy cost	-1.5 %	-116 %	+0 %	-11.0 %	-30.0 %	-100 %
FT change in total energy cost	-5.6 %	-37.4 %	-2.2 %	-12.8%	-28 %	-37.6 %
static yearly amortisation	31,000	17,575	10,000	21,700	115,000	11,250
change in total cost (%)	-4.6 %	-5.4 %	-2.0 %	-8.9 %	- 20 %	-29.7 %
change in total cost (EUR/a)	-147,700	-2,900	-98,694	-49,443	-307,671	-42,154

TABLE VIII
RETURN ON INVESTMENT (A)

Customers	Customer A	Customer B	Customer C	Customer E	Customer F	Customer G
change in total energy cost with FT (T EUR/a)	-179.1	-20.5	-108.7	-71.1	-422.7	-53.4
change in total energy cost w/o FT (T EUR/a)	-95.9	+21.6	+23.6	-49.9	-36.2	-16
total investment (T EUR)	620	351.5	200	434	2,300	225
return on investment with FT (a)	3.5	17.1	1.8	6.1	5.4	4.2
return on investment w/o FT (a)	6.5	+ inf	+ inf	8.7	63.5	14.1

consumption of FT to substitute fossil fuels) and is in general negative except on customers B and E.

- the change of the power cost component is positive when capacity is added at FT, but negative in customer F because capacity if reallocated from STT to FT.

The largest percentage cost reduction is found in Customer G with a substitution of all fossil fuels with heat pumps connected as conditional loads. The setting of customer F with large PV and large reallocation of electricity from STT to FT allows the third largest percentage cost reduction. The settings of customer B yields to the second highest reduction of energy costs after G but gets only at rank 4 after taking into account the expensive amortisation of PtG and battery. The overall impacts on cost reduction of Customer C is the lowest percentage of all customers but the third largest absolute cost reduction. The chosen setting is small compared to the total energy consumption of the facility of customer C because it can utilize only 20 % of its roof for PV and the large energy savings with WHR, considered without conditional loads, is excluded from the scope in the table.

C. Return on investment

The impact on total costs did not describe the profitability. Therefore, we document the return on investment (ROI) with and without reduced tariff in Table VIII. In five cases, ROI lie with FT up to 6 years. The ROI is 17 years in Customer B because the potential of new PV is small and the chosen PtG and battery are expensive. In absence of the reduced FT, the financial situation is more difficult in all six customers, but at different levels. In Customers B and C, the connection of the new loads would result in a net increase in the total energy costs so investment can never be amortised. In Customers F and G, the new loads would reduce the energy costs, but not enough for an attractive amortisation (ROI of 63 and 14 years). Only the new loads of customers A and E could make sense without the introduction of the FT.

D. Discussion

The six case studies were based on configuration of real pilot customers. The type of loads and installed capacity values were set in an iterative process with site visit and discussion of results of several capacity roll-out settings. But the combination of loads of different types per customer overlaps detailed effects of particular type of aggregate. The longest return of investment is observed at customer B, configured with new PtG and batteries, and the concept of conditional loads probably does not provide a sufficient incentive for PtG. Future work may analyse of the profitability of each aggregate individually and their order of installation. An expected outcome is that the incentive system is not adequate for each type of aggregate. An improved version of this incentive could include lower values of taxes and fees for conditional loads of type PtG and batteries than of type PtH. Under current configuration, the concept of conditional loads is the enabler of the addition of the new loads in customers B, C, F and G and of the associated reduction fossil fuel consumption and greenhouse gas emissions. To confirm this statement, a sensitivity analysis over the specific investment costs of the expensive technologies (PV, Battery, PtG, etc.) and over the costs of gas and electricity would be necessary. We discuss briefly the case of the least profitable technology, the PtG. To amortize 1 kW of PtG at 900 EUR/kW in 10 years of lifetime, one needs to generate yearly operation savings of at least 100 EUR/a (90 for the amortisation and 10 for the connection as conditional load) with the daily load scheduling minimizing energy costs. The electrolyser runs in two main cases, either in hours of oversupply of PV with too low spot price for a fed back to the grid, or in hours of import of electricity at FT.

- Around 200 kWh per kWp of PV fall on weekends and can be in excess. When the revenue of PtG is higher than the spot price, the excess goes to the electrolyser. According to the spot price 2035, each kWp of PV increases the revenue of 2.77 EUR/a. In Customer B with 7 kWp of PV per kW of PtG, it represents 19.4 EUR.

- The saving in the second case is the difference, whenever positive, between saved gas and imported electricity at FT. The sum of savings was 4.5 EUR over 458 hours in the spot price 2016 but 7.3 EUR in 361 hours in the spot price 2035. Sufficiently low spot price become rare until 2035 but more profitable due to increased volatility.

Both components at FT save 19.4+7.3=26.7 EUR/a. The FT brings PtG closer to the profitability than STT, but it does not reach it. The battery of customer B improves the revenues of the PtG but it is still far from covering the full 100 EUR/kW/a. The second component (substitution of gas by import at FT) raise upon changes in three parameters:

- 10.2 EUR/a by a doubling of the spot price 2035.
- 18.3 EUR/a by a drop of taxes and fees for PtG to 0.
- 138 EUR/a by a doubling of the gas price 2035.

Out of these three factors, the raise in gas price would have the most significant impact in the profitability of the PtG unit. The result is less sensitive upon a change in the specific technology costs from Table III. Excepted new loads of type PtG (for which other new business models investigated in future works would be required), we can conclude that the described capacity additions (PtH, PV, batteries and other types) would be attractive and their installation will modify the congestion situation of the grid. In the fictive worst-case scenario, all customers would be located in the same branch of a middle voltage grid. The asset of the grid with the highest load would be immediately after the entry node. The sum of installed unconditional loads will drop from 8475 kW to 7175 kW with the reallocation of 1300 kW from STT to FT in customer F. The sum of installed capacity of conditional loads will raise from 0 to 4275 kW. If this asset has a capacity of 8.5 MW for unconditional loads and the same for conditional loads, no congestion would occur in absence of new loads, and only at most 50.3 % of the band for conditional loads could be used in peak hours. In [4], an additional opportunistic customer X with only conditional loads at 7 MW created a grid congestion and an automatic traffic light system managed this case. The investigation whether new loads are economically realistic was left for a future work in [4] and it is now verified.

Finally, the last preoccupation of customers is the quantification of the additional costs related to the two types of limitation of the proposed system of conditional loads:

- The worst case is the grid failure: conditional loads remain switched off until the grid is repaired, instead of being reactivated like unconditional loads as soon as the DSO has connected the two branches of the grid supply ring. The damage is mostly only a loss of comfort and of flexibility. The frequency and duration of such cases would require additional data collection of each single manipulation of the redundancy by DSO. Statistics of system average interruption duration index measures the system performance with its redundancy but not without the redundancy. However their values of 15 minutes per year in Germany i.e. 0.003 % of the time and less than 0.1 % in Europe [7] show the rarity of these events.
- The second type of limitation is the regular grid congestion that would happen when too many customers of the same branch wished to synchronise their conditional loads at the same particular moment. This congestion can only happen after the connected capacity would have roughly doubled, which is not going to be soon even if all fossil energy consumption is switched into the power grid. If this congestion happens, the concept described in [4] allows energy customers to reschedule their conditional loads at other hours, which results in a slightly higher energy costs due to the variations of spot price but a maintained level of comfort.

The non-quantified cost of these two intrinsic limitations of conditional loads is negligible to have any significant impact on the long-term profitability of the roll-out of these new loads.

VI. Conclusion

The concept of capacity additions without security of supply, which was shown to be technically able to avoid grid congestion in previous works, was missing an economic evaluation of costs and revenues of these capacity additions. Based on six case studies with simulation of load management schedules for each day of a year, we have shown that the roll-out of the new flexible loads is attractive with the introduction of the reduced tariff as a compensation of the abandon of security of supply. In four out of six cases, we could also show that the roll out would not have been financially possible as unconditional loads in the standard tariff, even with the reduced technology prices of the future. This illustrates that the differentiation of tariff system based on the nature (regular vs. flexible) of loads can be the enabler of a radical transformation of the role of power grid towards a reduction of fossil fuel consumption and greenhouse gas emission.

Acknowledgment

The research received funding from the ERANet Smart Grids Plus initiative. We thank Alpiq, HSLU, ZHAW, aski, primeo energie, Stadtwerke Crailsheim and pilot customers.

References

[1] S. Gyamfi, S. Krumdieck and T. Urmee *Residential peak electricity demand response: Highlights of some behavioural issues*, Renewable and Sustainable Energy Reviews, 2013, vol. 25, p71-77.
[2] A. Mohsenian-Rad and A. Leon-Garcia *Optimal residential load control with price prediction in real-time electricity pricing environments* IEEE Transactions on Smart Grid, 2010, vol.1, p 120-133
[3] J. Bagemihl, F. Boesner, J. Riesinger, M. Künzli, G. Wilke, G. Binder, H. Wache, D. Laager, J. Breit, M. Wurzinger, J. Zapata, S. Ulli-Beer, V. Layec, T. Stadler and F. Stabauer *A market-based smart grid approach to increasing power grid capacity without physical grid expansion*. Computer Science - Research and Development 33(1-2), 2018.
[4] R. Christen, V. Layec, G. Wilke and H. Wache *Technical Validation of the RLS Smart Grid Approach to Increase Power Grid Capacity without Physical Grid Expansion*. Smartgreens 2019: 123-130.
[5] U. Albrecht et al. *Analyse der Kosten Erneuerbarer Gase*, December 2013
[6] P. Ralon et al. (IRENA) *Electricity Storage and Renewables, Costs and Markets 2030*, October 2017
[7] N. McCoy Council of European Energy Regulators asbl *CEER Benchmarking Report 5.1 on the continuity of Electricity Supply*. Report Ref C13-EQS-57-03, 11 February 2014 .