OPTIMAL SCHEDULING OF A P2G PLANT IN DYNAMIC POWER REGULATION AND GAS MARKETS

Robert Weiss[1], Jouni Savolainen[1], Pasi Peltoniemi[2], Eero Inkeri[2]

[1]VTT Technical Research Centre of Finland Ltd. P.O. Box 1000, FI-02044 VTT, Finland

[2]Lappeenranta University of Technology, Lappeenranta, Finland

Introduction

The purpose of this study was to investigate the operational profitability and benefits of dynamic scheduling of a Power-to-Gas (P2G) plant in a multi-use sectoral integration case. A Power-to-Gas (P2G) plant has the potential to combine dynamically the production of synthetic power based fossil-free CH_4 (SNG) that can be used in the gas grid or for mobility, primary frequency control for the power grid, O_2 for local industrial processes, excess H_2 for distribution, CO_2 capture from local processes, as well as heat and steam. In this context we present an optimization model for such P2G production scheduling, which helps to display the benefits from operating dynamically in the markets and local industrial environment.

The SNG production chemistry with hydrogenation of carbon dioxide (CO_2) has received attention in recent years with recognition of CO_2's key role of as a precursor chemical to SNG and other chemicals. Technological reviews of recent decades' SNG production technologies have been provided by (Kopyscinski et al., 2010) and (Rönsch et al., 2015). Energy storage and renewable energy system integration aspects of SNG have been studied for example by (Jürgensen et al., 2014; Moeller et al., 2014; Ma and Spataru, 2015), while (Vandewalle et al., 2015; Kötter et al., 2016) have studied the interactions of P2G with the gas, electricity, heat and/or CO_2 markets.

This paper aims to address the *operational scheduling and dynamic profitability* of a P2G process. Especially noteworthy is that we study a multi-use P2G process. In other words the process acts a source of SNG but supplies also at the same time contracted and required O_2 to an industrial site and actively participate in control of the power grid. As industrial integration example, we use O_2 supply contracting to pulp mill, with considerable electrolytic O_2 utilization potential indicated by (Kuparinen et al, 2015) and SNG production potential indicated by (Breyer et al, 2015)

Methodology

The work presented here is a case-based, engineering economy research utilizing operations research methods and modeling. In the following we first discuss the power market background, and then present the case under study and the computational scheduling optimization models.

Power markets and frequency containment reserve in northern Europe

Deregulated electricity markets are generally divided into wholesale energy markets managed by power exchanges, and ancillary service markets managed by Transmission System operators (TSO). Energy is sold and purchased typically on international day-ahead markets for the 24 hours of the next day, and adjusting energy trading can be done on intraday power markets, see e.g. (Nordpool, 2016) for Nordic System, Baltic countries and Germany, or (EEX, 2016) for Germany, Austria, France and Switzerland.

Situation in the Nordic countries are well described by (Grande et al, 2008), and these principles and processes have not changed significantly. The situation of Nordic countries compared to central Europe countries Netherlands, Germany and Poland (UCTE area) is also described in (Grande et al, 2008). We compare in Table 1 two representative markets situations today, Finland and Germany:

Table 1 Wholesale day-ahead market and Frquency containment reserve market principles in Finland vs Germany

		Finland	**Germany**
Wholesale markets	**Day-ahead market**	**Nordpool**	**EPEX and Nordpool**
	Type	Marginal price	Marginal price (daily auction), Pay-as-bid (continuous trade)
	Day-ahead market resolution	1 hour	1 hour
	Closing time, Day-ahead bids	12:00 CET+1	12:00 CET (EPEX)
	Publishing time, Day-ahead contracts	15:00 CET+1	12:55 CET (EPEX)
	Intraday market(s)	Nordpool	EPEX and Nordpool
Short term Market for Frequency Containment Reserves	TSO(s)	Fingrid	Tennet, 50Hertz, Amprion, Transnet BW
	Market place	**fingrid.fi**	**regelleistung.net**
	Product for frequency-controlled operating reserves	FCR-N (symmetrical between +-0.1Hz)	Primärregelleistung (symmetrical between +-0.2Hz)
	Product for frequency-controlled disturbing reserves	FCR-D (asymmetrical, activated below 49,9 or 49,7 Hz)	No active market
	Type	Marginal price	Pay-as-bid
	Day-ahead market, resolution	1 hour	*No hourly market*
	Closing time, Day-ahead bids	18:00 CET+1	*No hourly market*
	Publishing time, Day-ahead contracts	22:00 CET+1	*No hourly market*
	Weekly market, resolution	*No weekly market*	1 week
	Closing time, Weekly bids	*No weekly market*	Week before, tuesday 15:00 CET

For a bidder, there are following fundamental differences: In Finland, the wholesales day-ahead marked is closed and published *before* bidding Frequency Containment Reserves (FCR), making clarity for a power plant or demand side bidder on the power resources available and own cost structure. Thus, in the Finnish system, a power plant that has not been able to sell any (profitable) energy production or a consumer that has bought only a minimum of power does not have to tie itself to bidding FCR with must-run obligations. The German situation is the opposite: the bidder must first submit Frequency Containment Reserves, ties itself to risky must-run obligations, and is *afterwards* forced to act on the day-ahead market to meet at least the must-run obligation. Here the bidder faces substantial wholesale price risks because of e.g. rapid changes in wind power production, forcing a must-run power plant sometimes to even pay for producing the minimum power level to stay online for the must-run obligation.

Case P2G process and gas deliveries

The structure of the case P2G process plant under study, which can produce SNG, oxygen (O_2) and grid frequency control services, is show in Figure 1.

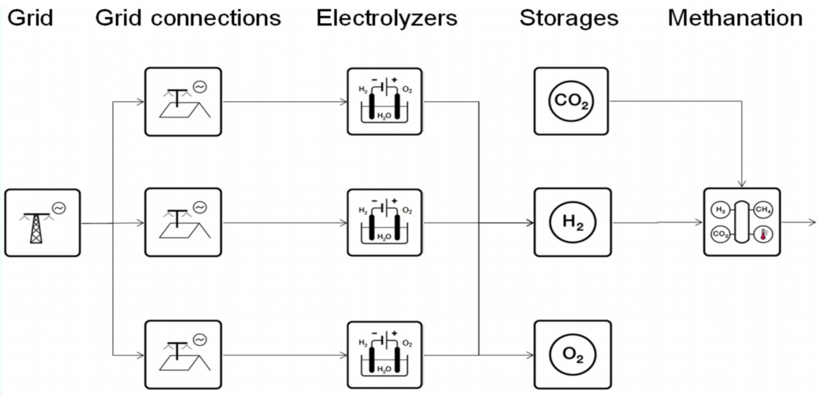

Figure 1 Flowsheet of the studied P2G process.

In this case process, 3 parallel water splitting electrolyzers of approximately 3MW$_e$ maximum power are each connected separately to the medium voltage power grid. These electrolyzers are all alkaline electrolyzers (AEC) operating in atmospheric conditions with nominal temperature at 70°C. From each electrolyzer hydrogen (H_2) and oxygen (O_2) product gas flows are extracted. Both product gases are fed to their respective gas storage lines. The H_2 storage line is a combination of a small low pressure vessel (LP) 6 m^3 at 0.95 bar, middle pressure vessel (MP) 50 m^3 operating around 16 bar used for balancing, and high pressure vessel (HP), 10 m^3 operating around 300 bar. The H_2 MP vessel is used to stabilize short term changes in hydrogen flow. Outlet flow from the H_2 MP vessel and an external source of CO_2 are fed, at a 4:1 H_2:CO_2 molar target ratio and target flow of approximately 1500 Nm^3/h, to a chemical methanation reactor vessel producing a flow of SNG. The O_2 storage line is a combination of a small LP vessel 1 m3 at 0.95 bar, MP vessel 50 m3 at 10 bar and HP vessel 20 m3 at 100 bar. Before the H_2 and O_2 pressure vessels are compressors as well as safety valves to the ambient air. Outlet flow from the O_2 MP and HP vessels deliver needed O_2 gas to a local industrial end customer.

The process can either be driven by the frequency of the electrical grid, utilizing a frequency controlled grid connection, or scheduled according to various combined O_2, H_2, SNG or heat needs. This depends on the plant techno-economics, contractual situation and dynamic market situation of both the products sold and power purchases needed. As can be seen from Figure 2, AEC electrolyzers have higher specific gas yields (H_2 and O_2 produced / AC power consumed) at low part loads than at high part loads. Together, this operating environment creates an interesting optimization case for part-load operation.

In our case study, we concentrate on delivering contracted steady-flow O_2 to a pulp mill whereas the other products SNG, excess H_2, and grid frequency control are providing additional revenues. We use SNG, O_2, CO_2 and H_2 prices as displayed in Table 2. To show the future potential of P2G, optimistic site estimates for O_2 value and CO_2 cost were used. For SNG, we used a site price that assumes own “green industrial gas” production to be free from the non-recoverable taxes and levies that the replaced fossil natural gas has to carry, and be sold approx. average 50 EUR/MWh site price. This SNG site price used was lower than reference CNG and biogas prices 1.20 – 1.50 EUR/kg indicated at refilling stations (Gasum, 2016), leaving some room for SNG distribution and similar costs.

Table 2 Industrial gas prices used in operational P2G optimization calculations.

IGas	Price type	Price	Unit	Reference
SNG	Sales price at site	0,70	EUR/kg	Eurostat, 2015: Average Natural Gas price to industrial customers in the EU, semester1 2015. Reported average for Finland 45 EUR/MWh, including all non-recoverable taxes and levies. Other EU countries ranged 28-62 EUR/MWh.
O_2	Sales price at site	0,08	EUR/kg	Breyer et al, 2015: 50 - 80 €/t value estimated for O_2 in Pulp Mill processes. We use the optimistic values.
CO_2	Cleaning and handling price at site, excluding steam need for CCS	0,01	EUR/kg	Breyer et al, 2015: 10 - 40 €/ for CO_2 exctracted in Pulp Mill processes. We use the optimistic values. CCS amine process steam need is covered by methanation steam.
H_2	Price at site: commercial 300-350 bar H_2	1,70	EUR/kg	Ruth, M. et al, 2009 (NREL) Estimated approximate value of 2 $ per kg H_2 at central steam reforming plant, including compression costs.

Optimization model

The optimization model handles the entire P2G process in Figure 1 from power grid ancillary services and day head market Spot-power purchases to the SNG production and contracted O_2 (and/or H_2) deliveries. In the sections below, the submodels of the P2G unit processes and gas deliveries are described.

Today, a forecasting and power bidding time horizon is generally not much longer than 1 day ahead, a free optimization is too risky and practically not possible for a very long timespan ahead. Instead, uncertainty risks can be handled by e.g. requiring that site gas storages should in the end of the day return within predefined narrow safety limits, to be ready for new situations the next day. Our scheduling optimization model is performing 24 hour day-ahead optimizations with a 1 hour resolution, requiring gas storages to return to the initial safety levels at the end of the day. In this way, we can also handle the spot and hourly primary frequency control markets, both being day-ahead markets. For our case, we are running such 24-hour day-ahead optimizations in a linked for the 365 consecutive days of the case year. The operation schedule dynamics were used and validated with a detailed dynamic process simulation model of the process in (Savolainen et al, 2016). For the German situation, the weekly optimization was implemented with the 24-hour day-ahead optimizations of the wholesales spot price, but with fixed FCR contract and price. The optimization model was implemented using LP/MIP techniques. As solver package, we utilized GLPK.

Electrolyzer submodels

Each AEC is a separate unit model in the optimization. Our AEC unit models, suitable for LP/MIP optimization, have been estimated and validated with *in-situ* industrial operation data from MW-scale electrolyzers for the entire part load range between 20 and 100% operation, with good accuracy as shown in Figure 2. As can be seen relative errors are typically within ±2% in power consumption, except for the lowest part-load regions below 30%. For our analysis this lowest part-load region is of less importance, since scheduling results showed mainly high part load operations.

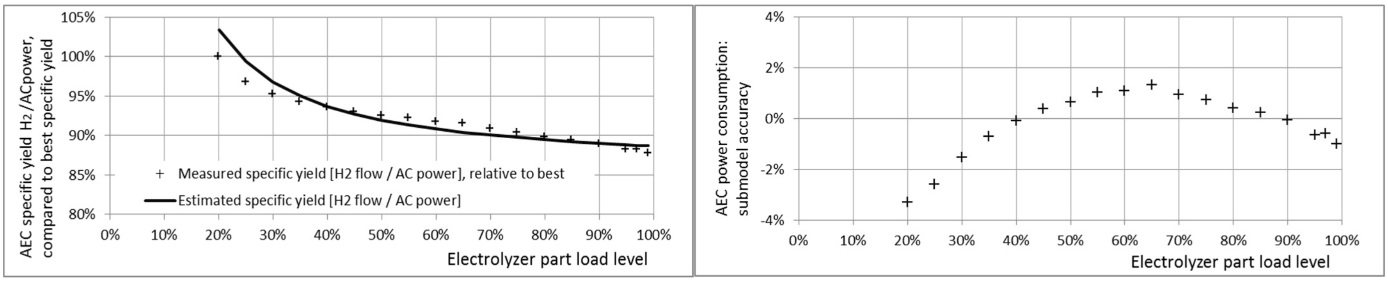

Figure 2 ***Left:*** **AEC specific yield [H_2 produced / AC power consumed] relative to best operation point, model vs in-situ measurements.** ***Right:*** **Optimization model accuracy on AEC unit AC power consumption.**

Below 20% part-load, the AEC must be shut-off and kept warm to avoid later cold start-ups. In our model, such behavior can be included with integer decision variables considering stand-by and cold start-up costs, but was omitted to speed up the case year calculations. Instead, reflecting process industry operation practices avoiding stand-by and start-up costs, each AEC was forced in the model to run at least at 20% part-load during the whole case year. Load changes in AEC can be done very fast, and are not restricted.

Hydrogen compression, storages and deliveries submodels

The H_2 produced in the AEC models is led to a H_2 MP storage model, connected in cascade to a HP storage model. The LP storage at atmospheric pressure could be neglected due to small relative size compared to other vessels. Power consumption for H_2 compression to MP vessel and further on to HP vessel are modelled using H_2 mass flows and nominal maximum pressure lift operating points (0,95 to 16 bar, and 16 to 300 bar) using same specific compressor curves utilized in Tähtinen et al. (Tähtinen and Sihvonen, 2016). In case of overproduction, H_2 can be vented in the model, i.e. lost to the air, before compression to the MP vessel. From the H_2 HP stora-ge, 300 bar high pressure H_2 can be delivered for remote distribution with e.g. trucks. In our case analysis, we assumed a daily truck filling of high pressure H_2 at the end of the day, but for quite a low market price (set to 1.7 EUR/kg H_2). From the H_2 MP storage, 7 bar or higher pressure H_2 can be delivered directly online to the methanation process and/or delivered to other direct local needs (via e.g. pipeline). In our case analysis, all H_2 MP-deliveries were directed to the methanation process.

Methanation process submodel

The methanation submodel in the optimization is based on a dynamics approximation of recent research results in the catalytic methanation field, including (Götz et al., 2015) suggesting that catalytic methanation is quite resilient to load changes and such changes are merely restricted by the speed of the reaction heat removal and speed of H_2:CO_2 feed control. (Götz et al., 2015) indicated also, that a dynamic operation range of at least 70-100% might be feasible. Therefore, instead of requiring a simple constant feed to the methanation reactor, we made a simple approximation of the load change process and controls behaviour as calculated in (Savolainen et al, 2016). Following their results in a H_2 feed change ramp, the H_2 content in the reactor increases and CH_4 content temporarily goes down below acceptable SNG level, before the process reaction and feed ratio controls adapt to the new feed level. This causes a delay in SNG production output, which was approximated and included in our optimization model. Below a certain part-load, the methanation must be shut-off and kept warm to avoid later cold start-ups. Especially cold start-ups are expensive. In our model, such behavior can be included with integer decision variables considering stand-by and cold start-up costs, but was omitted to speed up the calculations for our case year analysis. Instead, similarly to AEC submodel, the methanation was forced to run during the year between 70% part load and 100% full load operation. The CO_2 needed in the methanation was assumed to be captured with an amine process utilizing by-product steam from the methanation. Since our case example deals with pulp mill integration, were modern pulp mills generally are self-sufficient in lower grade heat and steam, we expect that remaining low grade steam and electrolyzer heat are practically of low value for such a mill and were neglected in this analysis.

Oxygen compression, storages and delivery submodels

Like the H_2, the O_2 produced in the AEC models is led to an O_2 MP storage model, connected in cascade to a HP storage model. Power consumption for O_2 compression to MP vessel and further on to HP vessel are modelled using O_2 mass flows and nominal maximum pressure lift operating points (0,95 to 10 bar, and 10 to 100 bar) using same specific compressor curves utilized in Tähtinen et al. (Tähtinen and Sihvonen, 2016). In case of overproduction, O_2 can be vented in the model, i.e. lost to the air, before compression to the MP vessel. From the O_2 storages, O_2 is delivered directly to local site needs (via e.g. pipeline). In our case analysis, we assumed a compulsory contract of fixed O_2 delivery flow to a neighboring pulp mill.

Plant power balance, wholesale power purchases and ancillary service contracts

In the optimization model, structures to handle electrical energy hourly SPOT priced purchases from the wholesale day-ahead market, power transfer fees and taxes together with the P2G plant hourly power balance are implemented. In addition, TSO ancillary service contracts for either fixed longer term contracts e.g. week to year, or hourly contracts based on day-ahead bidding are included for simultaneous contracts of symmetric frequency-controlled normal operation reserve (FCR-N) and asymmetric frequency-controlled disturbance reserve (FCR-D). If such frequency-controlled ancillary service contracts are entered, they have to be covered for the entire symmetric and/or asymmetric range during the contract duration by the plant electrolyzer capacities. In this study, we used year 2013 for Finland for wholesale spot power (Nordpool, 2016), FCR hourly prices and yearly contracts (Fingrid Oyj, 2016) as indicated in Table 3.

For this case study, a simple forecast and bidding strategy was included: The day-ahead (Day+1) wholesale spot power prices and FCR-N and FCR-D prices were forecasted to be same as for a 24-hour period before the bidding moment, e.g.. the prices of the previous day (Day-1). In addition, a simple maximum spot price limit, and FCR-N and FCR-D minimum prices limits were used. Such a strategy is possible in "marginal pricing" markets, but not in "pay-as-bid" markets like the German ancillary service weekly market.

Results

For our case P2G plant and case year 2013, optimum O_2 constant supply contract was found to be 80% of the electrolyzer capacity. Within 65-90% O_2 constant supply contract, the net income was almost same, which is displayed in Figure 3. Above 70% O_2 supply level, FCR-N will gradually be substituted by more FCR-D and SNG. Below 70% contract level, the electrolyzer H_2/O_2 production does not decrease, SNG production will stay at the 70% level and produced O_2 will to larger extent be lost and vented to the air.

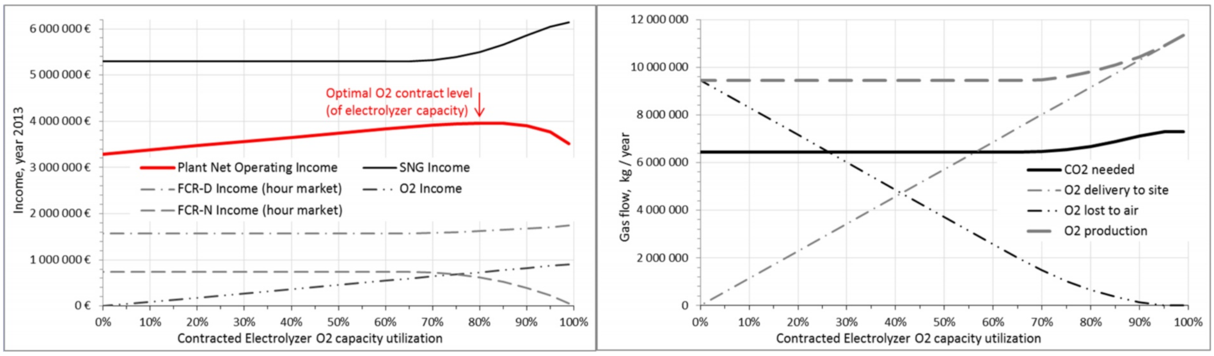

Figure 3 Impact of contracted O_2 level on plant net operating income *(left)* and on CO_2 needed and O_2 produced, delivered or lost *(right)*

The hourly FCR bidding provided superior net operating income compared to yearly FCR contracts or no use of FCR contract, as shown in Table 3, but is on a daily basis very volatile as indicated by Figure 4. For hourly contracting, examples on daily detailed operation schedules are displayed and validated in our co-study (Savolainen et al, 2016).

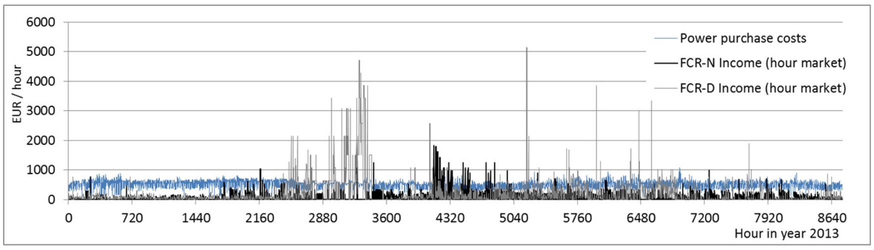

Figure 4 FCR income and power purchase costs (Spot, ave price 41,15 €/MWh + tax&transmission 25 €/MWh) of best hourly scenario.

Our simple previous day price forecast and bid price limit strategy for day-ahead bidding showed good results. For the best hourly FCR bidding scenario, a 100€/MWh maximum spot price limit bids would have resulted in 31 rejected purchase hours during 2013. Using a 1€/MWh minimum price limit on FCR-N and FCR-D bids (to avoid unpaid hours), would have resulted in 6207 and 6314 contracted hours for FCR-N and FCR-D, reaching 70,2% and 78,2% of the theoretical maximum FCR-N and FCR-D incomes.

In all scenarios, power cost was the superior cost component, being as high as 98% of the purchase costs. The electrolyzers' share of P2G plant power consumption was estimated to be approx. 96%, including transformer losses. The H_2 and O_2 compressors accounted for remaining approx. 3% and 1%, respectively. Hydrogen was entirely used for SNG and high pressure H_2 was generally not sold.

Table 3 Impact of FCR contracts on plant net operating income (excluding maintenance and personnel costs).

Contracted O_2 Level		**No FCR**	**FCR-N & FCR-D yearly contracts** *FCR-N 14,36 €/MW,h (2013)* *FCR-D 3,36 €/MW,h (2013)*		**FCR-N & FCR-D hourly contracts** *FCR-N average 36,32 €/MW,h (2013)* *FCR-D average 23,38 €/MW,h (2013)*	
kg O_2 per hour	O_2 capacity utilization	Plant Net Operating Income	Plant Net Operating Income	Improvement to best "No FCR"	Plant Net Operating Income	Improvement to best "No FCR"
1241	95 %	1 848 272 €	2 072 815 €	12 %	3 771 925 €	104 %
1045	80 %	1 816 881 €	1 996 283 €	8 %	3 959 656 €	114 %
849	65 %	1 684 706 €	1 832 069 €	-1 %	3 881 505 €	110 %

For the best hourly FCR bidding scenario, a CO_2 allowance price of 50 €/tonCO_2 would have increased our incomes with 8.5%. If a higher price, e.g. 1.0 €/kg, for mobility SNG could be achieved the best scenario would have provided 62% more net income. If SNG had a similar non-recoverable taxes as natural gas, and be sold at 0.5 €/kg, this would have provided 39% less net operating income. The differing electricity market operation conditions between Finland and Germany showed clearly differing operational profitability. Hourly FCR-D would have given 1340000 €/y income in Finland for year 2013. This alone provides 57% more net income than the German situation would provide, since they have no FCR-D market. This large FCR-D income must however be considered with care, since other years than 2013 had considerably lower hourly FCR-D prices, typically averaging between 7 and 15 €/MWh. For a fair comparison between Germany and Finland we evaluated a situation with FCR-N only bidding, without FCR-D, using same yearly average price 36.31€/MWh = 6100 €/MW,Week but with differing bidding mechanisms in Table 1. Actual German FCR prices today are substantially lower, 2500-4000 €/MW,Week. Despite same average market prices used, the Fingrid hourly market provided 202000 €/year, i.e. approximately 9% better net operating income to the bidder than the German weekly market. Main reason for this was the flexibility in the hourly market bidding, allowing producing more SNG when FCR-N prices were too low.

Discussion and conclusions

The aim of the paper was to investigate operational scheduling and dynamic profitability of a multi-use P2G process in two very different market environments. We calibrated an optimization model towards existing industrial electrolyzer and upcoming methanation technologies. To show the future potential of industrially integrated P2G, we utilized an optimistic gas price scenario and a year of documented high hourly market prices of ancillary services with normal wholesale power prices, probably what we can also expect in a system with highly intermittent power generation. The analysis showed that P2G can be very profitably operated in a highly volatile ancillary service market, like the Finnish FCR market, still meeting obligations to supply contracted industrial gas and produce SNG for mobility use. Furthermore, even if the major income comes from SNG production, each of the P2G side-products plays a very significant role for the overall profitability and must be utilized. From the results, we can see that there are circumstances where P2G can reach a considerable net operating income. This can be a help in future investment decisions.

The case comparison Finland-Germany showed that there can be for the same P2G plant configuration considerable profitability differences depending on the FCR market design. Yearly markets and the current pay-as-bid weekly market in Germany restrict the dynamical scheduling of a P2G plant, which reduces considerably P2G flexibility and the operation profitability. Therefore, we recommend that an *hourly market* should be implemented with day-ahead or at least weekly bidding process, which could help demand side actors that would like to bid full ancillary services and flexibility only for part of a day or part of a week.

For future research, the P2G scheduling optimization presented should be enlarged to more comprehensive risk management purposes, as well as direct intermittent renewable production. For a broader product perspective, the optimization could be utilized also in other industries, like district heating, and other PtX products like methanol, syngas, olefins or ammonia.

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Optimal scheduling of a P2G plant in dynamic Power, Regulation and Gas markets

Authors and their degrees with corresponding author indicated:

Weiss Robert[1], Lic. Tech. robert.weiss@vtt.fi, corresponding author

Savolainen, Jouni[1], M.Sc. (Tech.),

Pasi Peltoniemi[2], D.Sc. (Tech.),

Eero Inkeri[2], M.Sc. (Tech.),

[1]VTT Technical Research Centre of Finland Ltd., P.O. Box 1000, FI-02044 VTT, Finland

[2]Lappeenranta University of Technology, Lappeenranta, Finland

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