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Wartsila comments part 3 of 3

Additional submitted attachment is included below.

POWER SYSTEM OPTIMIZATION BY INCREASED FLEXIBILITY

Agile gas-based power plants for affordable, reliable and sustainable power

A WHITE PAPER BY WÄRTSILÄ AND ENERGY EXEMPLAR

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EXECUTIVE SUMMARY:

Great amounts of renewable energy are installed into power systems at state, regional and national level, often due to fulfill legislated mandates or renewable portfolio standards (RPS). While renewable energy is a means for reducing reliance on fossil fuels and decreasing greenhouse gas emissions, it is increasingly evident that there is need for flexible thermal fleet to help balance the renewables. The primary fuel considered for new builds is natural gas, and the default technology to meet capacity and flexibility needs is gas turbines in simple or combined cycle. In this work we show the substantial system benefits of increased flexibility and improved dynamic dispatch capability. This is achieved by exchanging traditional gas turbine based plants in the planning process to gas-fired combustion engine plants. The combustion engine plants have zero start costs and faster start and ramp rates than comparable state-of-the-art gas turbine based plants.

We use the California Independent System Operator (CAISO) as representative of a large system implementing an aggressive 33% RPS by the year 2020. Through simulation of the year 2022, we compare reliability, operational costs, water consumption and CO2 emissions for the CAISO system assuming 5.6 GW of new-build gas turbine-based capacity against a 5.6 GW scenario of combustion engine generation. For modelling, we use PLEXOS™, a dispatch simulation software by Energy Exemplar.

The rapid start times, superior efficiency and flexibility of gas-fired combustion engines are shown to increase the entire fleet efficiency within the CAISO system, by reducing cycling and starts/stops on existing combined cycles and optimizing provision of ancillary services. Flexibility combined with the superior reliability of multi-shaft engine plants are shown to reduce the number of hours of ancillary service shortfalls by 70%, and the magnitude (MW) of ancillary service shortfalls by more than 50%. The Combustion Engine Alternative scenario shows estimated ratepayer savings of 4–6%, compared to Base Case scenario with gas turbine plants. Water consumption is reduced by 25 million gallons per year, and CO2 emissions are curtailed by 1.1% (> 500,000 short tons per year).

1. INTRODUCTION

Many regions are embarking on aggressive renewable energy mandates, often referred to as Renewable Portfolio Standards (RPS). These are often legislated requirements that by some future year, a certain percentage of a system's energy consumption (in GWh) be provided by renewable energy, mostly wind and solar. For example, in the USA, 29 states, Washington DC and two US territories have legislated RPS commitments from 10% to 40% by 2015 to 2030 (DSIRE, 2013). The intention is to promote the usage of renewable generation and thereby meet state or regional targets of reduced emissions from the utility sector. The increased usage of variable renewable generation creates new challenges on our utility systems.

There has been surprisingly little exploration into what would happen if the choice of gas-fired generation was expanded and diversified to include other modes of commercially viable, mature technologies suitable for utility-scale power generation. In this work we explore the value of one such technology: medium speed, state-of-the-art combustion engines. As these engines are more flexible than gas turbines with higher response speeds and faster starts, this analysis looks at the system value of increased flexibility and response performance.

We examine installing combustion engine plants instead of gas turbines (GTs) and/or gas turbine combined cycles (GTCCs) for the California Independent System Operator (CAISO) as representative of a large power system with aggressive RPS standards. We address the following issues:

- Thermal fleet CO_2 emissions
- Water consumption
- Operational costs of the system
- System reliability
- Integrating more renewables

We will show that some characteristics of combustion engines make them an attractive alternative to the gas turbine paradigm and can be helpful towards answering in the affirmative to all of these issues.

Definitions

Ancillary services: capacity which the system operator uses to maintain the required balance between generation and load. Also known as balancing services. Divided as contingency and operational reserves. Contingency reserves (spin and non-spin) handle system events, such as a trip of the largest generator. Operational reserves (load following and regulation) are used to balance fluctuations in net load.

Load following: operational reserve to handle discrepancies between the hourly and 5 minute schedules, where schedule differences can arise due to deviations between forecasted and actual renewable output (net load variations).

Net load: the total electricity demand minus renewable generation. This remaining part of the demand has to be met with power generation that can be dispatched, i.e. generating units that can be ramped and/or started and stopped as needed.

Non-spin reserve: off-line capacity available to come on line in the event of a contingency, must satisfy requirements for start-up time and ramping capability

Regulation: operational reserve, balances discrepancies between 5 minute schedule and real time

Spin reserve: online contingency reserve, synchronized to the grid.

2. MODERN COMBUSTION ENGINE POWER PLANTS

Modern combustion engine power plants use internal combustion machines that burn natural gas. Unlike GTs, combustion takes place in cylinders, much like a car engine. However, similarity with automotive applications ends there as engines for power plant applications have state-of-the-art control systems and are optimized and developed unlike anything found in the transportation industry. Features of modern combustion engines include:

- Modular (10 to 20 MW per unit) capacity for projects up to 500 MW or more
- Highest simple cycle efficiency (46–48% depending on engine model).
- Very high part-load efficiency
- Insensitive to temperature: no derate on output/efficiency until > 100F/37C
- Insensitive to altitude: no derate on output/efficiency until > 5000 ft/1500m
- Minimum stable loads of 30% (per engine), as low as 1% for a large multi-engine facility
- Engines can ramp from 30% to 100% load in less than 1 minute (ramp rate of 100+%/minute)
- Start times of 1–5 minutes, with MWs to grid in 30 seconds.
- High reliability and availability
- No minimum run time
- Minimum down times of 5 minutes
- Unrestricted number of starts/stops per day with no impact on O&M (O&M is hours-based only)
- Automatic Generation Control (AGC), remote dispatch and black start capability
- No process water consumption due to usage of closed loop radiator cooling
- Proven technology, power plant applications worldwide, with decades of experience. Wärtsilä, the leading supplier has over 55 GW of power plant references, 2.7 GW in the USA.

In simple cycle a 300 MW plant with 15 engines (20 MW apiece) can operate at loads as low as the minimum 30% load of one engine, or 6 MW, and with shutting engines down sequentially the plant can be operated over the entire load range (6 MW to 300 MW) at or near full load efficiency by cascading engines on and off.

Combustion engines can also be configured in combined cycle, with approximately 10% more power available from the steam turbine, yielding net efficiencies of 50% or more. This implies that in combined cycle mode, 90% of plant capacity can be online within 5 minutes at over 46% efficiency, and full combined cycle output available in an additional 40 minutes.

Capital costs of combustion engine plants (50 MW to 500 MW) are competitive with modern aeroderivative GTs and combined cycle plants. In terms of emissions, they meet the strictest regulations and have been permitted and installed in states like California, with some of the most stringent emissions requirements in the world.

The leading supplier of combustion engines for power plant applications is Wärtsilä, with over 55 GW of stationary power plant references worldwide. Wärtsilä's combined cycle offering is trademarked Flexicycle™.

3. EXPLORING THE IMPACT OF COMBUSTION ENGINES ON SYSTEM PERFORMANCE

The system (CAISO)

One way to test the impact of increased flexibility on a power system is to simulate the system with a generation fleet with more dynamic capabilities and compare this to the same system using the currently planned resource additions. The system selected for this analysis is the California Independent System Operator (CAISO) in the year 2022. CAISO manages the delivery of electricity to 80% of the state of California and operates the energy and ancillary service markets across three major investor owned utilities. CAISO handles roughly 35% of the electricity load in the western United States.

California has legislative mandates to achieve a 33% RPS by the year 2020. Every two years the California Public Utility Commission (CPUC) issues a Long-Term Planning and Procurement Plan (LTPP) which evaluates capacity needs 10 years into the future. In the 2012 LTPP the CPUC identified approximately 5.63 GW of new-build gas turbine and combined cycle plants by the year 2022. Both the CAISO and the CPUC have recognized that net load fluctuations and ramping will impose considerable integration challenges on their system (CAISO 2014). Thus a test system was available for analysis, whereby the system could be evaluated with the original 5.63 GW of anticipated new-build gas turbines and combined cycles, and then compared to an alternative, where the 5.63 GW was replaced with medium speed combustion engines.

The model (2022 WECC model)

We made use of a publicly available PLEXOS™ database referred to as the 2022 WECC (Western Electricity Coordinating Council) model. PLEXOS™ is a dispatch simulation program that co-optimizes energy and ancillary services, similar to the way in which Security Constrained Economic Dispatch algorithms are used by North American system operators. WECC is the regional reliability entity for the Western Interconnection. The 2022 WECC model includes a basic transmission network among the largest regional entities, and operational information for every power plant in the WECC system. It also includes hourly projections for energy and ancillary services demand and thermal, hydro, wind and solar production. It provides a common framework from which system-wide analyses can be done, as well as state or local level analyses of any subregion of WECC. The 2022 and previous versions of the WECC model have been used by the state of California (CAISO 2011), consultants (e.g. E3 2014a) and by national laboratories (Lew et al. 2013) to explore issues related to renewable integration.

Modifications to the model: After consultation with the National Renewable Energy Laboratory (NREL), some modifications were made to better reflect operational capabilities of thermal plants and how they are represented in the model. These modifications are described in Appendix 1.

Choice of scenarios for CAISO: The CPUC 2012 LTPP evaluated 4 scenarios. After consultation with analysts from the CPUC we chose to evaluate "Base Case without SONGS". SONGS is a 2 GW nuclear plant that was ordered to shut down in 2013. The Base Case assumed "mid" growth load forecasts. Details can be found at (CEC, 2012). Fuel costs were built into the model based on the California Energy Commission Burner-Tip pricing forecast 2012–2022.

Ancillary services: Ancillary services (A / S), include operational and contingency reserves and are co-optimized with the energy supply. In the 2022 WECC model they are specified for subregions within WECC region (one of which is the CAISO system). Operational reserves include Regulation (up and down), set to roughly 1.5% of load, as well as Load following. Load following is an operational spinning reserve set aside to handle potential net load fluctuations. Specific to the CAISO system, hourly values (specified in the 2022 WECC model) for load following and regulation are calculated based on a stochastic analysis tool developed by the Pacific Northwest National Laboratory (PNNL) for CAISO. The requirements vary based on load and renewable buildout. Contingency reserves are specified to handle the largest outage in the system, and include Spin Reserve and Non-Spin, at roughly 3% each of load for every hour.

Simulation scope: The day-ahead hourly market was simulated for the entire WECC system for all 8,760 hours in the simulation year 2022. This approach simulates the least-cost dispatch of every plant in the system to serve energy and ancillary services (co-optimized). Results include output (MWh) and production cost (fuel + variable operations & maintenance + start costs + CO_2 emissions) of every unit serving energy or ancillary services, as well as the marginal cost for energy and each ancillary service by hour. From these results various metrics can be calculated, such as capacity factor and annual provision (MWh and costs) of energy and ancillary service by asset type (GT, GTCC, ST, etc.). These and other results were extracted for the CAISO system from the 2022 WECC simulation results. Import and export of energy from the CAISO system were accounted for across interties with neighboring regions.

Two types of simulations were performed:

> Need runs: Full production cost model but with the maximum Load following up and Regulation up requirement for the month assigned to each hour, and with certain costs relaxed (such as start costs). Purpose is to apply a "worst case" ancillary service requirement scenario and thereby identify any potential capacity shortfalls independent of the economics associated with dispatchable generation.
>
> Production cost runs: Full production cost run with prescribed daily/hourly values for energy and A/S, and with all costs enabled. Purpose is to estimate CO_2, variable cost of annual fleet operation and to identify any potential shortfalls in generation or ancillary services.

The Base Case and the Combustion Engine Alternative

Two separate cases were defined. The Base Case assumes all new-builds (between 2012 and 2022) are exactly as specified by the California Public Utility Commissions 2012 LTPP: 5.63 GW of gas turbines in simple and combined cycle. The Combustion Engine Alternative performs the same simulation with the same assumptions and inputs, except instead of the 2012 LTPP gas turbine new-builds, an equivalent capacity of 5.63 GW of combustion engines in simple and combined cycle were assumed to be built instead.

Base Case: Defined as including the GT based new-builds (simple and combined cycle) in the 2012 LTPP, expected to be online by the simulation year 2022.

- 760 MW of industrial GTs
- 1,992 MW of aeroderivative GTs
- 2,875 MW of GT combined cycles

All parameters for these units were maintained exactly as specified in the 2022 WECC model.

Combustion Engine Alternative: Defined as removal of all new-build GTs and GTCCs from the Base Case and replacement by 2,752 MW of combustion engines with operational characteristics similar to the Wärtsilä 18V50SG engine. The value of 2,752 MW is the sum of industrial and aeroderivative GT capacity defined in the Base Case, so it is a direct substitution of simple cycle combustion engines for simple cycle GTs. In addition, 2,875 MW of combustion engines in combined cycle substitute for the new-build GTCCs. These are equivalent to Wärtsilä Flexicycle™ plants. Details of the units and operational characteristics (start times, VOM rates, start costs, full load output and efficiency on a per-plant basis) can be found in Appendix 2.

4. FINDINGS

Combustion engines reduce capacity shortfalls for ancillary services

The first set of simulations was the "Need Runs", which determined if enough capacity exists to meet system needs. Shortfalls were only observed for the peak day, 7/22/2022. For the Base Case (GT buildout) there were a total of 6 hours of shortage with a maximum shortfall of 2.71 GW, compared to the Combustion Engine Alternative with 2 hours of shortage with a maximum shortfall of 1.37 GW (Figure 1).

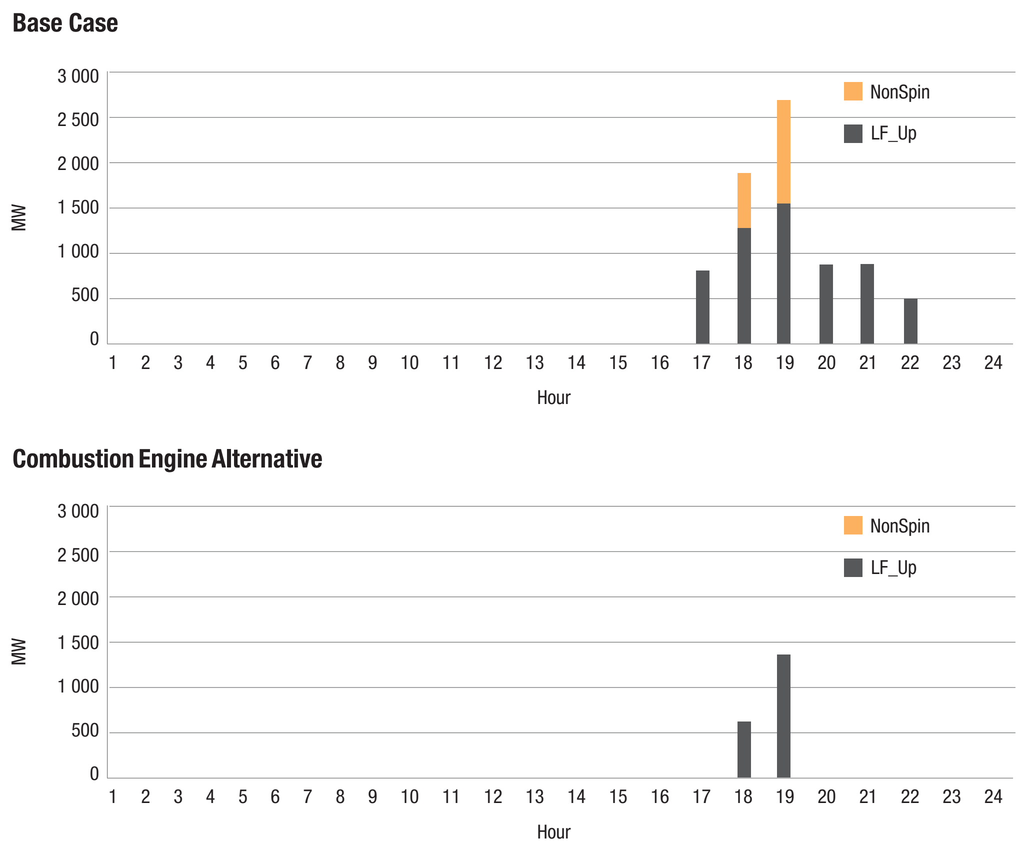

Figure 1. Shortfall by ancillary service type Base Case and Combustion Engine Alternative.

Combustion engines reduce CO_2 emissions by 1.1%

Medium speed combustion engines in simple cycle require approximately 8-10% less fuel per MWh than the most efficient gas turbines on the market, and hence emit at least 8-10% less CO_2/MWh. The efficiency advantage of combustion engines becomes even greater at part-loads.

Combustion engine combined cycles, in contrast, use about 10% more fuel (and emit about 10% more CO_2) than modern, advanced GTCCs at full load. However, 90% of a combustion engine combined cycle's output is available within 5-7 minutes at a heat rate of 8,400 to 8,500 Btu/kWh (@ 46% net, LHV efficiency), with full combined cycle output and efficiency in 45 minutes from start command. In contrast, gas turbine combined cycles get roughly 2/3 of their capacity within 15 minutes of the start command, at a heat rate of 10,800 Btu/kWh (@ 35% net, LHV efficiency) and up to 1 or more hours before full load output and efficiency. In short, per start sequence, the combustion engine combined cycle emits less CO_2.

So the question is, does the capacity replacement in the Combustion Engine Alternative ultimately increase or reduce the CO_2 emissions from the CAISO fleet? The efficiency of the thermal fleet in the Base Case was 0.7% lower (7,444 Btu/kWh) than that of the fleet in the Combustion Engine Alternative (7,390 Btu/kWh). This was influenced in large part by the higher efficiency of the Wärtsilä units and by the increased capacity factor at higher efficiency for the combined cycle fleet (52.89% cf at 7,168 Btu/kWh in Combustion Engine Alternative relative to 49.86% cf at 7,215 Btu/kWh in the Base scenario). In addition, existing combined cycles in the Combustion Engine Alternative started 20% fewer times per year (on average) than in the Base Case. Taking the enhanced fleet efficiency and reduced number of GTCC starts into account, the Combustion Engine Alternative delivered a CO_2 reduction for the CAISO thermal fleet of 1.1%, which equates to more than 500,000 short tons/year. **In brief, this system optimization is realized not just by having a more efficient simple cycle fleet but through a better utilization of the combined cycle assets once the dynamic, variable portion of their dispatch has been taken over by more flexible assets, in this case combustion engines.**

Combustion engines reduce water consumption

Given the concern over water rights and availability in the western United States as a whole, and in California in particular, it can be assumed that any new combined cycles installed by year 2022 will minimize water consumption by using air-cooled condensers, or ACC's (instead of cooling towers). The combustion engine combined cycles (Flexicyle™) were assumed to use ACC's as well. Each of these combined cycle configurations still has a water concern related to boiler makeup.

Combustion engine combined cycles use 1/3rd the water of a GTCC: Detailed calculations for boiler makeup water flow rates are quite dependent on water chemistry, the equipment involved, the types of water treatments used, unit cycling characteristics etc. In lieu of detailed calculations, we can take a heuristic approach. Approximately 30% of a GTCC's output is from the steam turbine. A similar sized combustion engine combined cycle would get approximately 10% of its power from the steam turbine. Without detailed calculation, it would be safe to say that a combustion engine combined cycle would use only one-third of the water for boiler makeup of that required from a GTCC per MWh. This is a conservative estimate as combustion engine combined cycles use low pressure boilers, so attendance to water chemistry (and the need for makeup) are reduced relative to the larger, superheated boilers used in GTCCs.

Combustion engines could save more than 25 million gallons of water per year: The 2012 LTPP highlighted 1,550 MW of 100 MW/unit class aeroderivative units which often use water injection, and are representative of some of the most advanced gas turbines available. Power and efficiency are augmented by two means, an intercooler and water injection. The intercooler reduces the temperature of air flowing into the combustor, thereby increasing its density, which allows for more power extraction per unit of fuel consumed. Water injection is then added to increase mass flows through the rotors and increase power production.

Assuming the 100 MW class turbines noted in the 2012 LTPP are offered with water injection and dry coolers (radiators) for intercooler heat rejection, the database GTPRO V23 (www.thermoflow.com) estimates water injection rates at approximately 24.53 gallons/MWh (or 0.1 m3/MWh). The four plants across which the 1,550 MW were added generated, in the Base Case production cost run, 1,041,346 MWh for the year 2022. This equates to 25,544,224 gallons (97,000 m3) of water consumed for water injection. In the Combustion Engine Alternative, these units were replaced with Wärtsilä 18V50SG capacity, which is also air cooled but requires no water for injection.

Combustion engines optimize ancillary service provision

Combustion Engines in multi-unit plants have much higher plant reliability (on a per 100 MW basis) than gas turbine alternatives. In addition, combustion engines have faster ramp rates and shorter start times. Taken together, this implies that in a supply/demand context, an equivalent amount of combustion engine capacity will provide a greater supply of available ramping capacity, primarily for upward ancillary services – and, consequently, a reduced marginal cost of provision of those ancillary services. These units maintain a very high efficiency across the load spectrum, from minimum output (Pmin) to maximum output (Pmax).

In the Combustion Engine Alternative, combustion engines provided greater amounts of Load following up (LFUP), Regulation up (RegUp), and Spin and Non-spin reserves, than the units they supplanted in the Base Case (Figure 2.-5.). In addition, adding 5.63 GW of combustion engine capacity in lieu of the LTPP GT-based buildout, reduced the provision of LFUP, RegUp and Spin reserve by existing GTs and GTCCs. In particular, the existing fleet of GTCCs, in the Combustion Engine Alternative, are tasked less with part-load operations at reduced efficiency to provide uplift ancillary services. This allows them to run more hours at or near full load and their maximum efficiency (see efficiency gain discussion in prior section on CO_2 reductions).

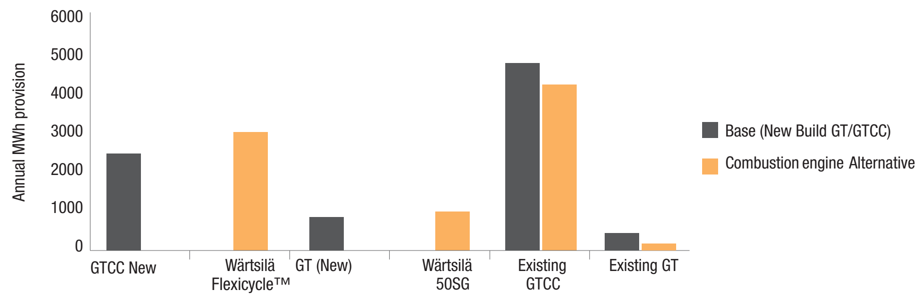

Figure 2. **Provision of Load Following Up (LFUP) ancillary service for the two scenarios. Combustion engines provide 30% more LFUP than the gas turbine/Base buildout, and reduce provision of LFUP by the existing GTs and GTCCs.**

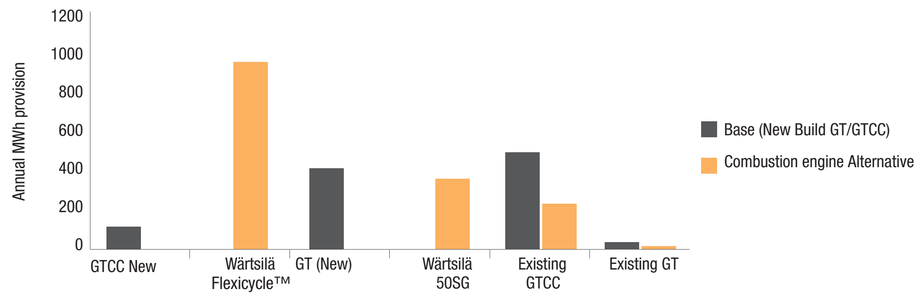

Figure 3. **Provision of Regulation Up (RegUp) ancillary service for the two scenarios. Combustion engines provide more than double the amount of RegUp compared to the gas turbine/Base buildout and reduce provision of this A/S by the existing GTs and GTCCs.**

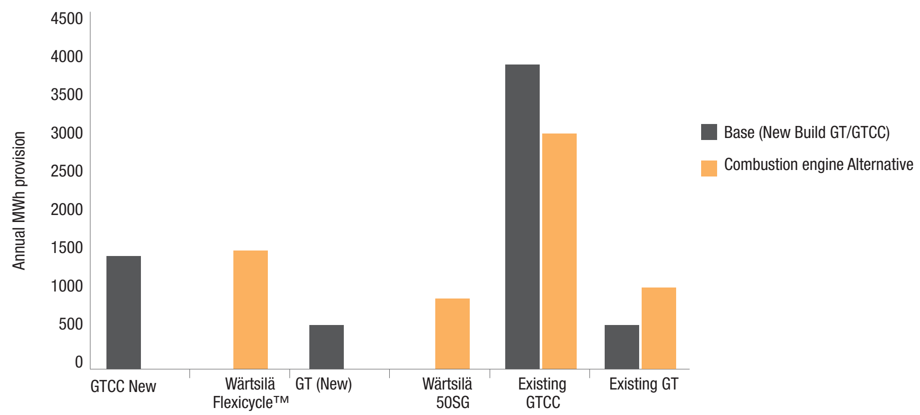

Figure 4. **Provision of Spinning Reserve (Spin) ancillary service for the two scenarios. Simple cycle combustion engines provide double the amount Spin compared to the GTs in the Base scenario.**

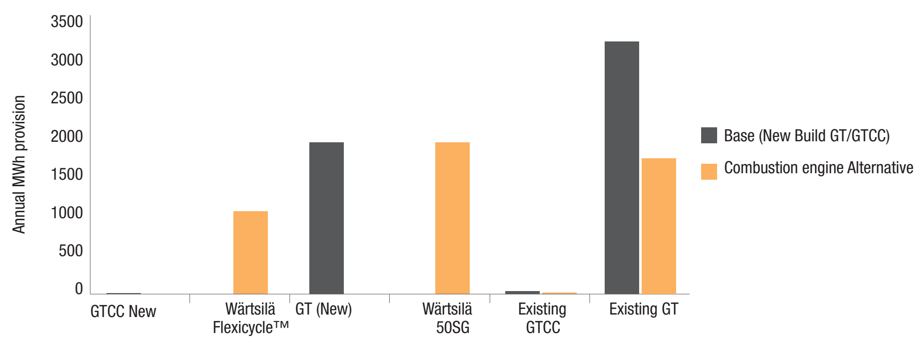

Figure 5. **Provision of Non-Spin ancillary service for the two scenarios. Due to fast start up times and high reliability, combustion engines provide 50% more Non-Spin than the gas turbine/Base buildout and reduce provision of Non-Spin by the existing GTs by 50%.**

Combustion engines reduce wholesale generation costs by up to 6% per year

Wholesale generation costs were calculated as follows for each hour based on full PLEXOS™ production cost runs:

1) Energy cost as the MWh (generated) times the marginal price.
   a. Marginal price is the $/MWh (Fuel + VOM + Emissions) for the last generator added to the dispatch stack in the model, which is reflective of the marginal unit.

2) Ancillary service cost (by type) as the MWh required to fulfill A/S requirements times the shadow price of each A/S.
   a. A/S type included regulation up/down, load following up/down, spin reserve, nonspin reserve.
   b. Shadow price is the incremental cost ($/MW) to provide one additional MW of that service, reflective of the marginal cost (by type).

3) Shortfall cost as the MWh shortfall times a value of lost load (VOLL) cost for shortage (of energy or A/S by type)
   a. The VOLL estimate (simple form) applies a shortage cost of $15,000/MWh (NARUC, 2013).
   b. The VOLL estimate (less simple) applies a premium to shortage on uplift AS, specifically $50,000/MWh for load following up (E3, 2014).

Quantification of shortages: Shortages were only observed on the peak day (Table 1).

Table 1. Ancillary service shortages on peak day for both the Base Case and Combustion Engine Alternative

Peak day (7/22/2022) A/S shortages (MWh)	Base	Combustion Engine Alternative	Delta	% Reduction with Combustion Engine Alternative
Load following up	4,648	1,157	3,491	75%
Non-spin	1,505	0	1,505	100%

Quantification of wholesale level savings: The sum of items 1, 2 and 3 above were calculated as conservative proxies of savings. The calculated values were considered conservative as the marginal costs are based solely on production cost of the marginal unit and do not include any markups related to stakeholder bidding strategies.

Table 2. Estimated ratepayer savings with Combustion Engine Alternative under 3 assumptions for shortfall costs for ancillary services.

Annual costs ($,000)	Base	Combustion Engine Alternative	Delta	% Reduction with Combustion Engine Alternative
Energy cost	9,000	8670	330	4%
Non-shortage A/S cost	204	165	39	19%
Totals (no cost for shortfalls)	**9,204**	**8,835**	**369**	**4%**
Shortage A/S Cost ($15k/MWh)	92.3	17.4	74.9	81%
Totals (w/$15k/MWh for shortfalls)	**9,296**	**8,852**	**444**	**5%**
Shortage AS Cost ($50k/MWh for LFUP)	255	58	197	77%
Total (w/LF Up shortfall at $50k/MWh)	**9,459**	**8,893**	**566**	**6%**

5. MOVING FORWARD

The results of this analysis demonstrate that a diversified generation portfolio, one that includes combustion engine technology, can assist large power systems with renewable integration while simultaneously reducing CO_2 emissions and water consumption and reducing costs ultimately borne by ratepayers. For example, in this study simply changing a modest portion of the thermal fleet can improve operational profiles and capacity factors for combined cycles, and improve overall system efficiency. It should be noted that the purpose of this analysis was not to find the theoretically optimal mix of the different gas fired generation technologies for a future California system but rather to show one example of savings based on exchanging the new-build out from gas turbine based plants to combustion engine based plants. The benefits at the fleet level have been demonstrated for the CAISO system in a prior study (Kema 2013) as well as for the United Kingdom (Wärtsilä, Redpoint Energy 2013). The findings of this study and the others mentioned give rise to additional issues related to the benefits combustion engines bring to power systems.

Capital costs of combustion engines are competitive with gas turbine solutions (E3, 2014a). Their competitiveness in regards to providing affordable flexibility is increasingly recognized by international agencies. For example, the International Energy Agency reports that, with regards to provision of flexibility, the levelized cost of combustion engines is competitive with advanced combined cycles (IEA 2014).

System reliability can be increased with modular buildout of capacity in 10-20 MW increments. The unscheduled outage rate for a 20 MW Wärtsilä engine is on the order of 1%. For a five engine, 100 MW plant the probability that all engines will experience unscheduled outages at the same time is 0.01^10, or 10^{-8} %. Therefore the likelihood of system reliability impacts from outages per 100 MW of capacity is reduced relative to alternate capacity options that can only be offered in 100, 200, 300 MW or larger blocks.

Similar to findings by PNNL (Makarov et al. 2008) related to time response characteristics of energy storage, there is reason to expect that modular, fast start, high ramp rate combustion engine plants can meet the flexibility needs of power systems with less installed capacity. This is indirectly attested to in this study by the fact that with matching new-build capacity installed, there was a dramatic reduction in shortfall hours and magnitudes for ancillary services in the Combustion Engine Alternative scenario (Figure 1 and Table 1).

Can a diversified fleet help systems absorb greater amounts of renewable energy than a less diverse fleet? Yes. Multi-unit combustion engine plants can start in <5 minutes to full load, provide MW to the grid in 30s from the start command, and operate at very low minimum loads. This aspect alone would be of great value for power systems such as CAISO which expect to experience massive net load ramps in shoulder months as they approach their 33% RPS in 2020.

As solar and wind energy peak, the standard assumption is that combined cycle assets will cycle and/or be idled back to low loads (e.g. ISO-NE 2010; Lew et al. 2013). This is done so that when wind/solar production declines, the needed ramp capacity is available to meet the net load increase/ramp. Instead of idling large combined cycles at low loads, with commensurate increases in CO_2 production (by MWh) as their efficiencies are compromised, a capacity bank of offline combustion engine resources could meet net load ramps from an idle state. This would alleviate a potential problem highlighted in a recent report (E3, 2014b). In that report, it was noted that as RPS standards for California approach 40% or higher, there is a "lower net load bound" that limits the amount of renewable energy the system can utilize, especially during peak solar production hours. A certain amount of thermal generation must be kept online in a part-loaded state to meet the expected net load ramps as wind/solar production decline in the afternoon/evening. This, in turn, means that there is an upper bound to the amount of renewable energy the system can absorb. Banks of combustion engines can provide that needed ramp capacity from an unloaded state, which would reduce the lowest net load the thermal fleet could support, which in turn would allow for greater utilization of renewable GWh. **In other words, the system could integrate larger amounts of renewable energy by using less thermal generation if that generation had more flexibility.** In addition, this would further reduce CO_2 emissions on an annual basis.

The full potential of a diversified thermal fleet in terms of helping nations, states, ISOs/RTOs maximize renewable generation while minimizing CO_2 production is, at least in part, impacted by market rules in effect. In many cases these rules were created decades ago based on the capabilities of generation at that time and with no foresight into the emergence of renewable generation. In order to fully exploit the capabilities of a diversified portfolio (including combustion engines storage technologies and demand response) it is necessary for market designers to recognize the capabilities of today's technology. In this work we have shown the value of a diverse portfolio that includes medium speed combustion engines, based on current market rules in the context of the system modeled (CAISO). We hope this will stimulate further discussion on the broader issue of market design required to unlock the full potential of a diversified portfolio.

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APPENDIX 1. MODIFICATIONS MADE TO THE 2022 WECC MODEL

The following modifications were made to the 2022 WECC model

Part-load heat rates: In the 2022 WECC model a number of generating plants were assigned a single-point, full load heat rate. The PLEXOS™ software interprets this as the plant being capable of operating between its minimum and maximum loads (Pmin and Pmax) while maintaining full load heat rate. This is technically and physically not possible, and could result in ancillary service allocations for those specific facilities. This would require them to operate at loads below Pmax, based on variable costs erroneously calculated based on full load heat rate. Therefore we identified over 900 thermal plants in the WECC model with single point heat rates, and provided the PLEXOS™ model with assumed part-load heat rate profiles for these plants. These assumed part-load heat rate profiles were created for aeroderivative and industrial gas turbines, combined cycles and boiler/steam turbine plants, using output from the commercially available software GTPRO V23 (www.thermoflow.com). The part-load heat rates for each individual plant were then scaled from the full load heat rate in the model using the supplied profiles.

Max replacement parameter: Any plants within or associated with the state of California that had max replacement parameters had this parameter removed. In essence, the presence of this parameter implies a unit can supply full or part-load within 10 minutes from an idle state. This is incorrect when applied to combined cycles and steam turbines which may have start times in excess of 3 hours. A total of 1,039 MW of capacity was modified.

Start profiles: All combined cycles with no assigned start profiles were assigned WECC average start profiles (a total of 145 GTCCs).

APPENDIX 2. PERFORMANCE PARAMETERS FOR COMBUSTION ENGINES

Combustion engines engine plants were assumed to replace the following facilities in the 2022 WECC Model

Table 3. **Base Case gas turbine capacity and Combustion Engine Alternatives**

RESOURCE ADDITIONS (on line by 2022)	Base Case		Combustion Engine Alternative		
Plant	Capacity (MW)	GT Configuration	# of gas engines	Type	Capacity (MW)
Mariposa EC CT1, CT2, CT3, CT4	200	Aero	10	Simple Cycle	200
Sentinel_1 to Sentinel_8	850	Aero	43	Simple Cycle	860
Walnut Crk_1 to Walnut Crk_5	500	Aero	25	Simple Cycle	500
Escondido CT	45	Aero	2	Simple Cycle	40
SCE LCR*	100	Aero	5	Simple Cycle	100
SDGE LCR*	297	Aero	15	Simple Cycle	300
Marsh Landing CT1, CT2, CT3, CT4	760	Industrial	38	Simple Cycle	760
El Segundo 2_5 & El Segundo 2_7	550	GTCC	26	Combined Cycle	559
Lodi Energy Ctr	255	GTCC	12	Combined Cycle	258
PalmdaleHybrid	570	GTCC	27	Combined Cycle	580.5
Russell City Energy Ctr	600	GTCC	28	Combined Cycle	602
SCE LCR*	900	GTCC	42	Combined Cycle	903
Total	**5627**				**5663**

*** LCR = Local Capacity Resource Addition**

Table 4. Combustion engine performance on a per-unit basis. Plant sizes 500+MW obtained by arranging multiple units in parallel.

Parameter	Unit	20 MW medium speed combustion engine*	20 MW medium speed combustion engine in combined cycle **
Max Capacity	MW	20.00	21.5
Min Stable Level	MW	6.00	6.45
Load Point (30%)	MW	6.00	6.45
Load Point (50%)	MW	10.00	10.75
Load Point (75%)	MW	15.00	16.13
Load Point (Full Load)	MW	20.00	21.50
Heat Rate (30%)	Btu/kWh	10,501	9,404
Heat Rate (50%)	Btu/kWh	9,221	8,345
Heat Rate (75%)	Btu/kWh	8,711	7,993
Heat Rate (Full Load)	Btu/kWh	8,291	7,763
Max Ramp Up	MW/min	14.00	15.05
Max Ramp Down	MW/min	21.00	22.58
Run Down Rate	MW/min	18.00	19.35
Min Up Time	hours	0.03	0.03
Min Down Time	hours	0.08	0.08
Start cost	USD	0	0
VOM cost	USD/MWh	3.5	3.5

*** Performance based on a Wärtsilä 18V50SG engine**
**** Performance based on a Wärtsilä Flexicycle™ (18V50SG engine in combined cycle)**

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