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Experimental model validation and thermodynamic assessment on high percentage (up to 70%) biomass co-gasification at the 253 MW_e integrated gasification combined cycle power plant in Buggenum, The Netherlands

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HIGHLIGHTS

- Experimental test demonstration for high percentage (70%) biomass co-gasification in an existing IGCC plant.
- Development of a detailed off-design thermodynamic model for an existing power plant.
- Model is validated with actual test data and predicts plant performance with reasonable accuracy.
- Model is used to predict plant performance for 70% co-gasification with torrefied wood pellets.
- Exergy analysis indicates a potential for further plant optimization.

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ABSTRACT

High percentage (up to 70% energy based) biomass co-gasification tests have been carried out at the 253 MW_e coal based Willem-Alexander Centrale (WAC), Buggenum in The Netherlands utilizing steam exploded wood pellets to assess feasibility of scaling up and to address stringent EU emission requirements in the coming decades. This principal article for demonstrating high percentage biomass co-gasification in large scale IGCC power plants, presents the obtained experimental results with a detailed and validated steady state thermodynamic model developed as an aid to assess future plant operations. The validated model is also used to predict plant performance involving 70% co-gasification with two fuel blends of torrefied wood pellets since the desired power output of 230 MW_e could not be achieved with steam exploded wood pellets. The model predicts plant performance and process parameters with reasonable accuracy and gives a net power output of 173 MW and a net plant efficiency of about 37.2% with steam exploded wood pellets. A net output of 240 MW_e and net plant efficiency of 41.7% is predicted for 70% co-gasification with high lower heating value (LHV) torrefied wood pellets. Exergy analysis indicates largest thermodynamic losses in the gasifier and during combustion, providing additional scope for efficiency enhancement. The demonstration of such a high percentage biomass co-gasification test at a large scale power plant is of vital importance for further development of low emission/carbon neutral power plants. The presented test data also serves as a reliable and prime data source for modeling studies. The validated models could serve as a strong platform to plan real plant operation with various biofuels and carry out studies involving novel technology integration, retrofitting and plant optimization.

1. Introduction

The role of biomass co-gasification in clean and sustainable power production has been of major global interest as biomass utilization could lead power plants to be carbon neutral and possibly carbon negative (if carbon capture and storage (CCS) is employed) [1–3]. With growing environmental concerns and stringent emission requirements, research and development in high percentage biomass utilization in large scale power plants is highly important. With multiple initiatives and targets set by the European Commission like Roadmap 2050 [4], the 2030 framework for climate and

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Abbreviations

ASU	air separation unit
CCS	carbon capture and storage
CO_2	carbon dioxide
COS	carbonyl sulfide
EU	European Union
GCU	gas cleaning unit
GT	gas turbine
HRSG	heat recovery steam generator
HP	high pressure
H_2	hydrogen
HCN	hydrogen cyanide
H/C	hydrogen to carbon ratio
IGCC	integrated gasification combined cycle
IP	intermediate pressure
LHV	lower heating value (MJ/kg)
LP	low pressure
O/C	oxygen to carbon ratio
SCGP	Shell Coal Gasification Process
SOFC	solid oxide fuel cell
ST	steam turbine
SGC	syngas cooler
WGS	water gas shift
WAC	William Alexander Centrale

energy [5], 20–20–20 climate and energy package [6], one of the major priorities of the Dutch government has been to assess feasibility for biomass co-gasification to achieve high percentage renewable power production and carbon reduction [7]. Existing large scale coal based power plants like the 253 MW_e Willem-Alexander Centrale (WAC), an integrated gasification combined cycle (IGCC) plant in Buggenum, The Netherlands could be utilized for demonstration on a large scale. Also, biomass co-gasification has been seen as a more reliable and suitable technology compared to power production with other renewable power sources like wind and solar [7–9]. Consequently, biomass handling capabilities at WAC were extended with installation of a biomass silo and feed systems; continuous biomass co-gasification could thus be realized. Several types of biomass fuels like wood, chicken litter, paper sludge, sewage sludge and ground coffee beans were tested on a small and preliminary scale [10,11]. Coal still could be used as a cheap and abundantly available back-up fuel in case of fluctuations in the biomass supply [7].

The increased need for flexible and efficient power plants also demands research into load flexibility and polygeneration aspects. IGCC power plants have also been studied by many researchers considering these aspects [12–17]. In order to develop such flexible systems with reduced emissions and high efficiencies it is important to understand and demonstrate real off-design operation of the plant with experimental tests and thermodynamic models. Based on these considerations a biomass scale-up project was carried out at WAC to assess high percentage (70% energy based) biomass co-gasification.

1.1. Biomass scale-up project at WAC

Based on small scale tests, milled wood pellets turned out to be the most suitable bio-fuel for scaling up biomass co-gasification at WAC [18]. Use of woody biomass in an entrained flow gasifier designed for coal leads to a drop in the gasifier cold gas efficiency (ratio of chemical energy in syngas to the chemical energy in the fuel) due to the higher hydrogen to carbon (H/C) and oxygen to carbon (O/C) ratios in biomass [19]. Further, biomass gasification under the same conditions yields less chemical energy in syngas and more sensible heat [19]. The molar concentrations of carbon dioxide (CO_2) and water vapor (H_2O) also increase in the syngas at the expense of carbon monoxide (CO) and hydrogen (H_2) [19]. Increase in the sensible heat of syngas increases heat transfer requirements downstream and calculations showed that at maximum plant load the percentage of milled wood pellets (without pretreatment) in the fuel mix was limited to 15%.

The aim was to achieve a net electrical output of 230 MW while co-gasifying 70% biomass (target was set to 70% biomass in the fuel mix, energy based) [7,18]. It was thus decided to utilize pre-treated biomass for the fuel blend to assess operational feasibility without major plant modifications. Pre-treatment of biomass enhances the quality of the biomass feedstock in terms of its mechanical, thermal and chemical properties [19]. Steam explosion and torrefaction are two of the available pre-treatment technologies that upgrade ligno-cellulosic biomass (like wood) to a higher quality fuel (increased LHV) [19–21]. Steam explosion is carried out typically at 160–260 °C; where biomass undergoes an explosive decompression thus yielding biomass with increased LHV [19,21]. Torrefaction is an alternative pre-treatment method in which biomass is heated slowly to a temperature of 200–300 °C in a non-oxidizing atmosphere [19,21]. This causes the biomass to become brittle and hydrophobic with a decrease in the O/C and H/C ratios. The changes in composition and lower heating value (LHV) have a beneficial effect on the gasifier cold gas efficiency. Torrefaction can yield a higher LHV end product than steam explosion in a relatively simpler process, also because with steam explosion, a drying operation must be performed before densification and use in co-gasification applications [21]. In addition, the existing coal mills at the plant can be utilized to co-grind biomass.

High percentage (70% on energy basis) co-gasification tests were carried out with steam exploded woodpellets as the first step in the biomass scale up project [18]. The large scale biomass co-gasification test carried out by NUON/Vattenfall at WAC utilized commercially obtained steam exploded woodpellets, called "black" pellets. The pellets are produced with a sequence of processes like drying, thermal conditioning, milling and pelletizing [22]. Wood chips are first dried to reduce moisture content to <10%. The chipped wood is sealed in a pressure vessel and pressurized with steam. A thermal conditioning step is followed then with a sudden release of pressure. This blows the biomass and leads to a tight, hard pellet bonded together. These pellets could be shipped, received, stored, conveyed and milled just like coal in the existing mills. Investigations were also required to understand the technical feasibility of co-gasifying torrefied woodpellets at WAC. Detailed and validated system models can be an effective tool to evaluate plant performance with alternative and safe operating conditions; hence it was decided to develop thermodynamic models based on the WAC plant design as an important aid to predict and verify off-design plant performance.

In literature many studies can be found on IGCC modeling, mainly with coal [23–29] with a few studies on low percentage biomass co-gasification. Modeling results on IGCC systems have been reported for 20% co-gasification using sawdust [30,31]. Additional results with 20% co-gasification of sewage sludge, meat and bone meal were reported [32]. Valero et al. [33] presents modeling evaluation of the oxy-co-gasification process for various types of biomass up to 10%. Various techno-economic and thermo-economic evaluation studies have been reported for various types of biomass on small to medium scale (up to 20 MW_{th}) [34–39] and economic studies of large scale biomass based IGCC systems have also been reported. [40,41].

Majority of these modeling results rely on literature or small scale tests as a prime data source and reliability thus remains debatable. Also there exists an inadequacy in experiment based IGCC system assessments. Experimental studies have been reported on stand alone gasifier units, for e.g., by Fermoso et al. [42] where up to 10% co-gasification was studied with almond shells, olive stones and eucalyptus. A small scale (5.5 MW_e) 100% biomass (rice husk and agricultural wastes) based IGCC demonstration project was carried out in China [43] and Sydkraft AB has demonstrated a small scale (6 MW_e) biomass based IGCC power plant fueled by wood in Vaernamo, Sweden [44]. Small percentage (2–4%) biomass co-gasification test data was reported by Sofia et al. [45] for the 300 MW Puertollano IGCC power plant in Spain with a techno-economic analysis for high percentage co-gasification.

Review on literature shows lack of availability in IGCC plant operating data for high percentage biomass co-gasification in large scale IGCC plants. This work, for the first time in scientific literature, strives to present the demonstration and actual plant data for high percentage (70% on energy basis) co-gasification carried out at a large scale IGCC power plant. The co-gasification test was carried out using steam exploded wood pellets. The experimental test data has also been utilized to develop a detailed and validated steady state thermodynamic model. The off-design model has been developed based on our previous work involving the development and validation of a design base case (100% coal gasification) model [46]. A well understood and well explained demonstration of high percentage biomass co-gasification in an existing large scale IGCC power plant is of crucial importance. In this period of crisis for the power plant community where companies operating power plants are not able to justify their decisions to invest in new technologies and a growing environmental concern, it could help initiate a renewed interest in the development of carbon dioxide neutral (possibly negative if CCS is employed) power plants. A major engineering achievement as this could also be sufficient for effecting major changes in policies. The demonstration of the technology in such a large scale could help develop a renewed interest in biomass utilization among policy makers. This article in addition presents model predictions for co-gasification with torrefied woodpellets at WAC. The developed off-design models could be an important tool to plan real plant operation with various biofuels and to carry out further studies involving novel technology integration, retrofitting and plant optimization.

2. Plant overview and process description

The Willem-Alexander Centrale has been a key demonstration plant for coal based IGCC technology. The power plant was constructed in 1989 by Demkolec (defunct company now), a consortium of Dutch power producers [47]. It was originally a demonstration project (Demo kV-STEG) with the aim of proving the feasibility of the IGCC technology for power production on a large scale in The Netherlands. After the demonstration phase from 1993 through 1998 the plant was ready for commercial operation [47–49]. With the liberalization of the Dutch power market, N.V. Nuon Energy (subsidiary of the Swedish company Vattenfall since 2009) acquired the plant in 2001 with the main purpose of balancing the company's power supply and demand. In 2003, the company acquired Dutch power plants owned by the American power company Reliant Energy and this facilitated WAC to be operated as a base-load plant using coal and an increasing share of biomass [50].

Fig. 1 illustrates the primary components at WAC in a process flow diagram. The plant design is based on the Shell Coal Gasification Process (SCGP) in which pulverized fuel mix is converted to synthesis gas (syngas) under sub-stoichiometric conditions in a dry feed slagging entrained flow gasifier at elevated temperatures between 1500 and 1800 °C. The gas is subsequently cooled for cleaning to approximately 250 °C. Particulates, halogens, sulfur compounds, and other contaminants are removed to ensure that process equipment will not experience corrosion and, more importantly, combustion of the syngas results in virtually zero emissions with the exception of CO_2. The flue gas is then guided through a gas turbine generating power and the off-gas, which continues to exhibit a considerable amount of thermal energy, is directed through a heat recovery steam generator (HRSG), driving a steam turbine at three different pressure levels for additional power generation. As shown in the figure, the air cycle is 100% integrated. A detailed description of the plant can be found in our previous article [46].

Not all plant operating units/components have been included in the models; only those that are thermodynamically relevant. The auxilliary power consumption is however appropriately accounted for. The red dotted blocks shown in Fig. 1 have not been included in the model.

- **Coal/biomass milling and drying:** The fuel preparation unit involving milling and drying has not been modeled, but the electrical power consumption has been included in the total auxiliary load. The fuel composition of dried and pulverized fuel mix is used as an input for the gasifier.
- **Fly ash removal:** Fly ash cyclone and ceramic filter after gasification and the syngas cooler are modeled as a single fly ash separator.
- **Gas cleaning and sulfur removal:** The wet scrubbing section (wash columns) consists of two scrubbers in series, with an air cooler in the water recycle loop (water supply to the first scrubber is condensed water at the outlet of the second scrubber). In the model this is simplified to a single scrubber with excess water supply and appropriate temperature specifications. Sulfur removal (as H_2S/COS) is modeled with complete removal of H_2S from syngas with appropriate pressure and temperature specifications and partial removal of CO_2, taking into account the co-absorption of CO_2 (about 30%) during amine wash. The Claus-SCOT unit to produce elemental sulfur (S) from H_2S has not been included in the model.
- **Generator and waste water treatment:** The generator unit and waste water treatment are seen as thermodynamically irrelevant and therefore not modeled in detail. The mechanical efficiency of the generator has been taken into account and the power consumption in the waste water treatment has been accounted for in the total auxilliary load.
- **Air separation unit (ASU):** Majority of the auxiliary power consumption in the plant is by the air separation unit, particularly the oxygen and nitrogen compressors [46]. Power consumption by these compressors has been included in the analysis based on partial modeling and a scaling approach. A detailed explanation on this is given in Section 3.3.

3. Modeling approach and description

Cycle-Tempo, a Fortran based in-house modeling software package [51], is utilized for steady-state model development. The software has a system component library which can be assembled and modified by applying appropriate operating parameters to build a custom-made system configuration. Thermodynamic and

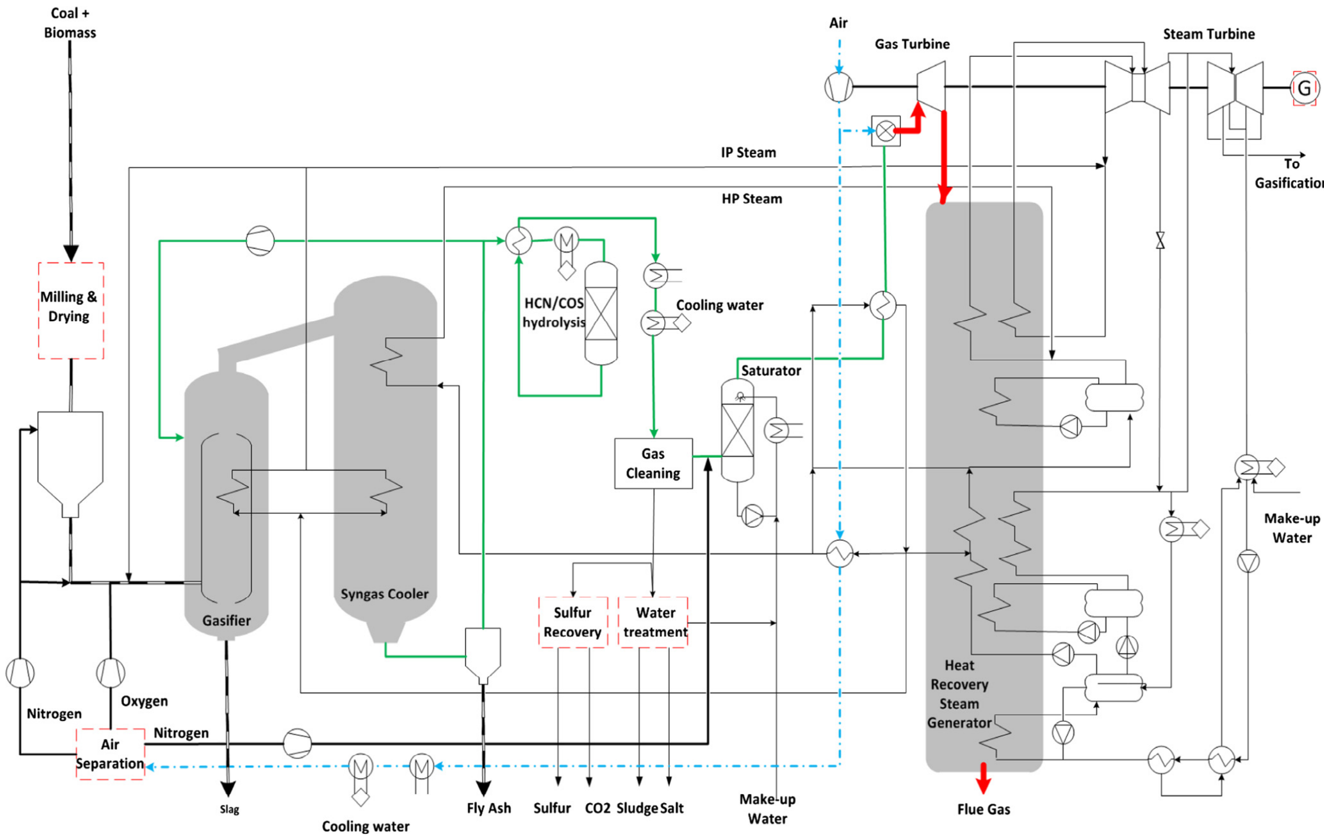

Fig. 1. Process flow diagram for the Willem-Alexander Centrale (WAC) – red dotted blocks have not been modeled in detail. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 1
Case definition – STEX represents the validation case. TORR-low and TORR-high are defined based on the LHV of the fuel blend with torrefied pellets.

Case	Feed fuel	LHV (MJ/kg)
BASE [46]	Australian Coal AUS-I	26.75
STEX	70% Steam exploded woodpellets + 30% Columbian coal	19.59
TORR-low	70% Torrefied woodpellets + 20% South African coal + 10% Columbian coal	22.87
TORR-high	70% Torrefied woodpellets + 30% South African coal	23.82

required transport properties are computed using the in-house software library FluidProp [52].

3.1. Case definition and fuel composition

Table 1 shows the definition for various cases considered in this study and the LHV of input fuel mix. The LHV for the coal powder in the BASE case was calculated based on design data and the Milne equation [46]. For the cases with biomass co-gasification, the LHV was obtained directly from NUON/Vattenfall. STEX represents the validation case for the co-gasification test with steam exploded woodpellets. Fuel mix for the STEX co-gasification test was obtained by mixing coal and steam exploded woodpellets with simultaneous operation of two on-site stacker-reclaimers at different speeds over the coal and steam exploded woodpellet piles. The velocities were set in a ratio such that the estimated share of biomass in the fuel mix was 70% (on energy basis). Heating values and bulk densities were taken into account for determination of the speed ratio. Two cases: TORR-low and TORR-high have been defined with different fuel blends and LHV based on NUON/Vattenfall's requirements for predicting co-gasification with torrefied pellets.

The fuel mix composition for the different cases are shown in Table 2. This represents the composition of the fuel mix fed to the gasifier after the drying operation. The ultimate and proximate analysis of the various coal and biomass feedstock can be found in Table A.1 (Appendix A). The STEX case fuel powder (ultimate analysis) and ash analysis was carried out by NUON/Vattenfall at their laboratories [53]. Ash consists of various compounds but mainly quartz (SiO_2), hematite (Fe_2O_3) and aluminum oxide (Al_2O_3). These three compounds with highest mole fraction are included in the fuel composition. Fuel mix for biomass co-gasification (both with steam exploded and torrefied pellets) contain negligible amout of limestone. Fuel composition for the BASE case is given only for reference.

3.2. Off-design thermodynamic model

Operation of the coal based WAC with 70% biomass co-gasification can be considered as an off-design situation in the context of modeling studies. An off-design analysis allows performance prediction due to change in the operating point of the system when compared to design case inputs and outputs. With an off-design model, the most important question to answer is whether the same electrical output can be maintained when co-gasifying biomass with coal. Also it is important to study several parameters like oxygen and fuel consumption, net plant efficiency, syngas flow and gas compositions. The BASE case IGCC model (design case) [46] is used to develop the off-design models for the cases with biomass co-gasification.

Table 2
Gasifier fuel mix composition for different cases – O/C and H/C ratios are highest for the STEX case and lower for TORR-low and TORR-high cases.

(Wt.%)	Al_2O_3	C	Cl	Fe_2O_3	H	H_2O	N	O	S	SiO_2	SO_3
BASE [46]	3.48	66.77	0.03	5.09	4.34	0.94	1.61	6.76	0.97	10.00	0.00
STEX	2.23	51.75	0.01	1.18	4.45	2.00	0.80	27.72	0.43	9.09	0.34
TORR-low	1.29	60.71	0.01	0.39	5.15	2.00	0.62	26.23	0.20	3.27	0.13
TORR-high	1.39	63.15	0.01	0.27	5.01	2.00	0.66	24.97	0.16	2.25	0.13

Cycle Tempo offers possibility to model off-design behavior of several components like turbines, heat exchangers, flash heaters, condensers and pipes.

- **Turbines:** Off-design calculations are possible for all types of turbines in Cycle Tempo. Traupel's formulae (a refinement of Stodola's cone law) are used to calculate off-design performance based on design case values [51,54,55]. Design case values of pressures, flow rates and specific volumes are needed to compute the off-design turbine inlet pressure. Eq. (1) shows the Traupel's formulae considered in Cycle-Tempo to calculate the off-design inlet pressure p from the specific volume v, mass flow rate m and the polytropic exponent n. Subscript α represents the inlet and ω the outlet. Sub-subscript o represents the design case value.

$$\frac{m}{m_o} = \frac{p_\alpha}{p_{\alpha_o}} \left\{ \frac{p_{\alpha_o} v_{\alpha_o}}{p_\alpha v_\alpha} \right\}^{1/2} \left[\frac{1 - \left(\frac{p_\omega}{p_\alpha}\right)^{\frac{n+1}{n}}}{1 - \left(\frac{p_{\omega_o}}{p_{\alpha_o}}\right)^{\frac{n_o+1}{n_o}}} \right]^{1/2} \tag{1}$$

Applying Poisson's formula:

$$p v^n = \text{constant} \tag{2}$$

$$p_\alpha = p_\omega \left\{ 1 + (k_o m)^2 \frac{v_\omega}{p_\omega} \right\}^{\frac{n}{n+1}} \tag{3}$$

$$k_o = \frac{1}{m_o} \left\{ \frac{p_{\omega_o}}{v_{\omega_o}} \right\}^{1/2} \left[\left(\frac{p_{\alpha_o}}{p_{\omega_o}} \right)^{\frac{n_o+1}{n_o}} - 1 \right]^{1/2} \tag{4}$$

k_o is only dependent on the design case values and is therefore a constant. The polytropic constant is derived based on Eq. (2) for design and off-design conditions. The use of Eq. (3) to predict off-design pressure for steam turbines is well justified [55] but the equation is modified for the gas turbine employing the equation for subcritical nozzle flow as shown in Eq. (5).

$$\frac{m}{m_o} = \frac{p_\alpha}{p_{\alpha_o}} \left\{ \frac{p_{\alpha_o} v_{\alpha_o}}{p_\alpha v_\alpha} \right\}^{1/2} \left[\frac{\left(\frac{p_\omega}{p_\alpha}\right)^{\frac{2}{n}} - \left(\frac{p_\omega}{p_\alpha}\right)^{\frac{n+1}{n}}}{\left(\frac{p_{\omega_o}}{p_{\alpha_o}}\right)^{\frac{2}{n}} - \left(\frac{p_{\omega_o}}{p_{\alpha_o}}\right)^{\frac{n+1}{n}}} \right]^{1/2} \tag{5}$$

- **Heat exchangers:** Cycle Tempo calculates the off-design heat transfer capacity UA (W/K) from the design case $(UA)_o$ value and mass flow rate (m_o) which mostly influences the overall heat transfer coefficient. The off-design heat transfer rate is calculated as shown in Eq. (6). This formula should not be used for discontinuous temperature profiles.

$$UA = (UA)_o \cdot \left(\frac{m}{m_o} \right)^{0.8} \tag{6}$$

- **Flash heaters:** Off-design calculations for flash heaters are not scaled with the UA-value since a reliable UA-value cannot be established for heat exchange between media showing phase changes. Depending on the ratio between the off-design mass-flow rate and the design mass-flow rate, temperature differences are adapted according to performance curves [56].
- **Condensers:** The heat exchanging area is an input to calculate the off-design behavior in Cycle-Tempo. With a known heat transfer and cooling water temperatures, the overall heat transfer in the off-design case will be calculated according to instructions as stated in the VDI Heat Atlas [57].
- **Other components:** Other major components of the system include the gasifier and combustor. Off-design modeling of these components demands knowledge and an accurate model for heat release/heat transfer in these components and variation in the gasification/combustion chemistry. For example, the heat absorbed by the gasifier walls/the heat transferred to the gasifier cooling system, etc. This heat depends on the thickness of the slag layer and models to predict this are very complex to develop and not readily available. Also due to high operating temperatures ($T_{gasifier}$ > 1500 °C, T_{comb} = 1050 °C), it is reasonable to assume a constant operating profile for these components.

Since the design case (BASE) model was converted to an off-design model, input data for individual components are mostly unchanged. This input data can be obtained from our previous article [46]. For components in off-design mode, the design case (BASE) model data is provided as additional input. Different fuel input mass flow rates, gasifier temperature and auxilliary load estimation are used for the off-design models, which are further elaborated in the following sections.

3.3. Auxiliary load estimation

Table 3 shows the auxilliary load as defined in the off-design models. The nitrogen and oxygen compressors in the ASU are major constituents of the auxilliary load. Off-design operation of the plant causes a variation in the O_2 and N_2 mass flow rate requirements. For off-design calculations, in order to estimate power consumption by the O_2 and N_2 compressors in a consistent manner, a scaling approach was used based on plant data with no co-gasification. The ASU utilizes as much air as the O_2 requirement in the gasification process. A fixed O_2 requirement (95% purity) by the gasifier leads to a fixed total N_2 production. The ASU produces two N_2 streams: impure N_2 used for syngas dilution and pure N_2 used mainly for pressurization, conveying of pulverized fuel and syngas purge systems. Production of pure N_2 is only slightly load dependent, the production of dilution N_2 is largely related to the

Table 3
Auxilliary power consumption – Major consumption is by to the N_2 and O_2 compressor in the ASU.

Parameter	Value (MW)
Dilution N_2 compressor	6.90
O_2 compressor	5.50
Pure N_2 compressor	2.00
Quench gas compressor	1.15
Cooling and feed water system	3.96
Fuel milling and circulation pumps	2.50
Tracing	0.70
Miscellaneous (GCU, etc.)	8.50
Total (variable based on operating condition)	31–35

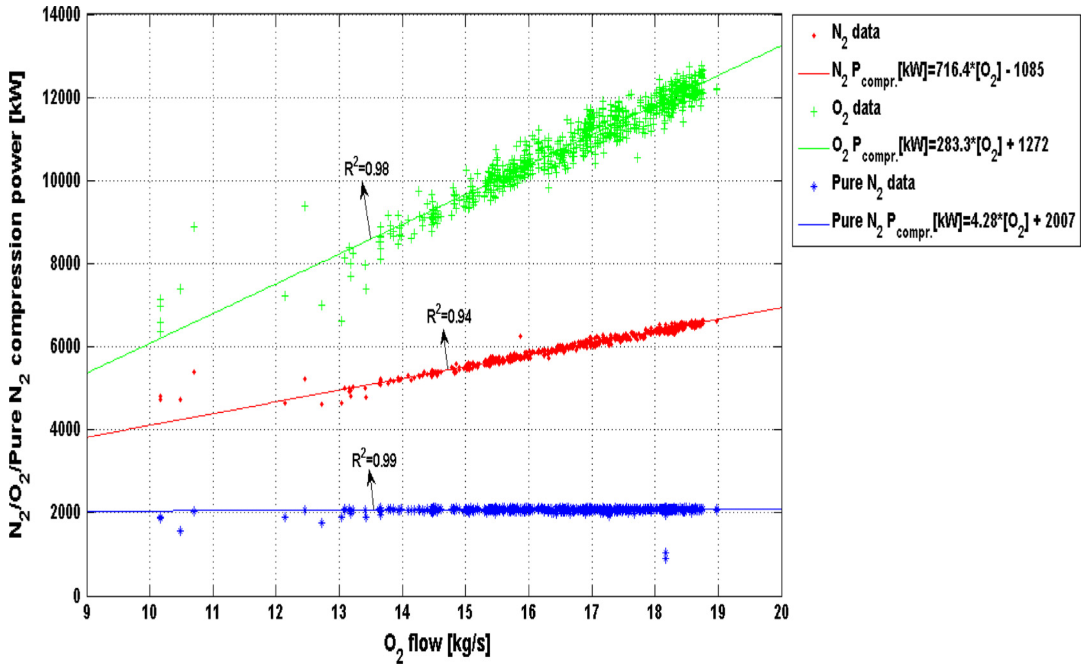

Fig. 2. Plant data showing dependency of ASU compressor power consumptions on gasifier O_2 flow.

O_2 demand. Plant data for 3 operating points (part-load) indicated a linear dependancy of O_2 flow on the dilution N_2 flow. Data plots of ASU power consumption versus O_2 flow were also available and indicated a linear correlation between compressor power consumption and the O_2 flow as shown in Fig. 2. With these data plots a linear correlation was established between N_2/O_2 compressor power consumption and dilution N_2/O_2 flow ($\dot{m}_{N_2}, \dot{m}_{O_2}$) respectively as shown in Eqs. (7) and (8).

$$N_2 \text{ compression power (kW)} = a * \dot{m}_{N_2} + b \quad b = 590 \tag{7}$$

$$O_2 \text{ compression power (kW)} = a * \dot{m}_{O_2} + b \quad b = 1252 \tag{8}$$

The variable part ($a * \dot{m}$) is simulated with a compressor in the model (see Fig. 3). A sweep in the N_2/O_2 mass flow rates was performed to estimate the value of b. The difference in the compressor power consumption between plant data and model output represents the intercept b. The obtained values of b have been then manually inserted in Cycle-Tempo. Change in the power consumption of the pulverizers has also been taken into account. A large deviation in the power consumption by other utilities wasn't expected; hence a constant value has been used for the other constituents of the auxilliary load.

4. Results and discussion

As the first step, implementation of the off-design model was verified by comparing results between the BASE case model in design [46] and off-design mode. This comparison showed identical results ensuring correct implementation of the off-design model. STEX case model (off-design mode) validation was then performed with actual experimental data. Section 4.1 gives the results and detailed explanation for the validation study. Model predictions obtained for TORR-low and TORR-high cases have been presented in Section 4.2 and an exergy analysis for the STEX and TORR-high case is shown in Section 4.3.

4.1. STEX model validation

Table 4 presents the experimental test data and the model validation results for the STEX case. The test data includes measurement of thermodynamic parameters at key locations in the plant. A few parameters like the gasifier temperature and saturator syngas outlet temperature have been calculated based on heat transfer measurements. In addition to these parameters, syngas composition was also measured which has been presented in Table 5. Fig. 3 shows the simplified Cycle-Tempo model scheme as an aid to interpret results from Table 4.

Table 4 shows a fair comparison between the STEX test data and the model output. Power output and net efficiency are predicted with reasonable accuracy (about 3% relative deviation). The model overpredicts the net power output by about 4 MW. This deviation is not necessarily caused by model simplifications; it has been indicated that aging of the plant and also an increased auxiliary load have caused a decrease in the net efficiency and power output over the years. In addition, during the test, the operation of a pilot CO_2 capture set-up (not included in the model) consumed roughly about 1% of the clean syngas, representing net power loss of about 1.8 MW.

Model output for the syngas cooler and the heat recovery steam generator (HRSG) show relatively high deviations compared to the test data. The model predicts a lower LP steam production from the syngas cooler (SGC) which can be attributed to fouling in the HP evaporator. The fouling in the HP section caused a shift in the heat transfer to the LP section of the SGC. The LP economisers with the LP steam generator in the water circulation loop, were to a very large extent able to compensate for the lack of heat transfer in the HP section of the SGC. The shift in heat transfer to the LP section causes a higher LP steam production in the SGC during real operation. A relatively high deviation is also seen in the SGC syngas outlet temperature which is attributed to fouling and a lower SGC heat transfer during real operation.

The syngas flow rate at several stages downstream the SGC is predicted with a fair accuracy. The higher syngas flow rate in the model at the outlet of the washcolumns is due to the modeling

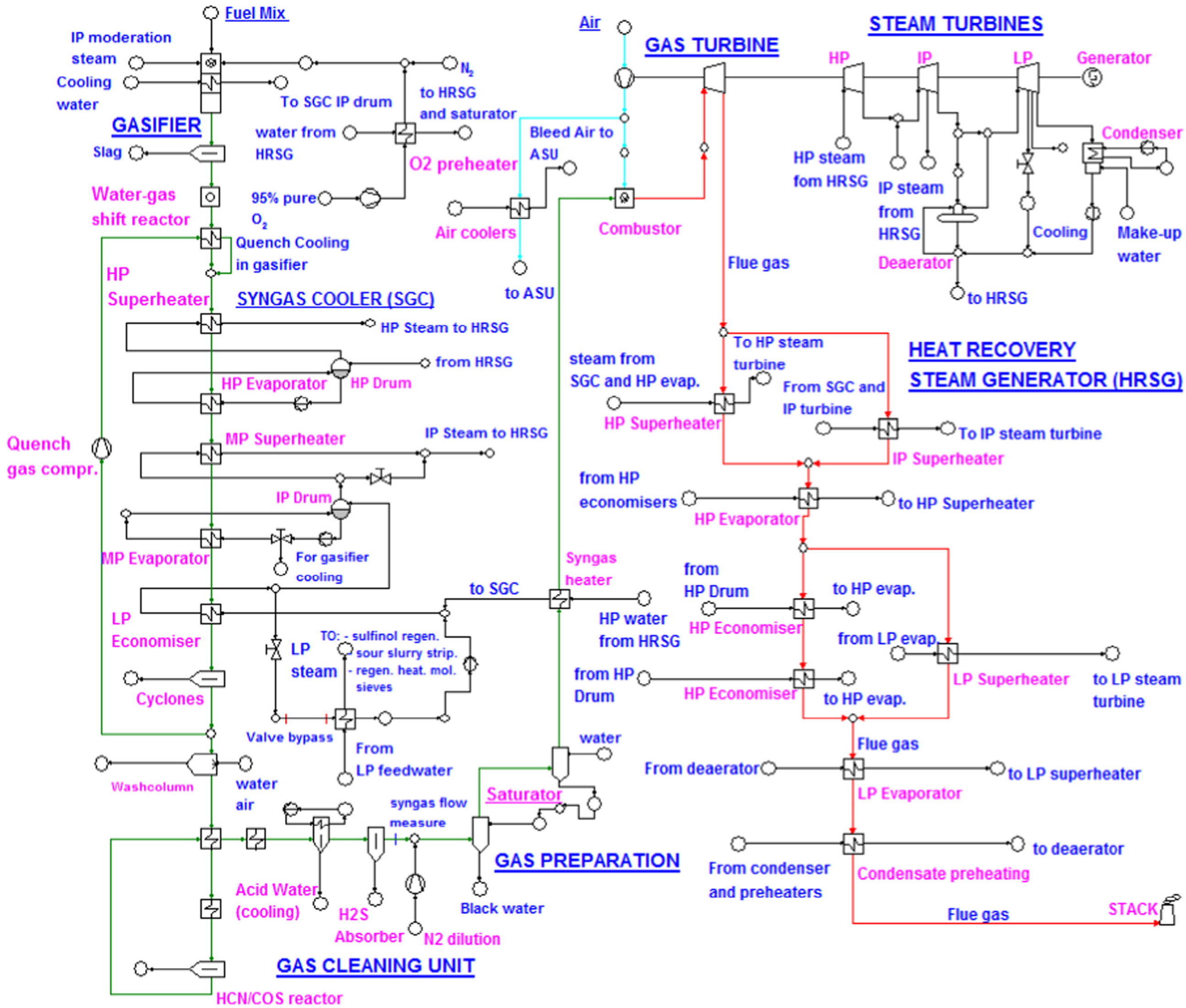

Fig. 3. Simplified Cycle-Tempo process scheme – green streams represent syngas flow, red streams represent flue gas and blue streams represent air flow. Streams indicating detailed process/heat integration have been excluded to maintain clarity. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

approach with a single separator as stated in Section 2. The outlet temperature of the second scrubber (in the water recycle loop) in the real plant was controlled around 110 °C. In order to obtain a higher water slip to the desulfurization unit, the scrubber could have been operated at a slightly higher temperature which causes a difference in the syngas moisture content at the outlet. As the scrubbing unit was modeled as a single separator, this fluctuation in the water temperature of the second scrubber could not be taken into account. Prediction of mass flow rates, temperatures and pressures across the gas cleaning unit, N_2 dilution and saturator matches well with the test data. The air compressor outlet pressure as well as the combustor outlet pressure are marginally underpredicted by the model. A possible reason for this could be the position of the GT compressor inlet guide vanes. In the plant, this was determined based on the ASU pressure instead of the turbine outlet temperature. An important aspect to notice with the experimental test is also that the gas turbine was able to cope up with the changes in flow rates and gas compositions.

The model also predicts a lower LP steam flow rate from the HRSG. This again can be explained by the shift of heat transfer from the high temperature to the low temperature section of the HRSG. One reason may be fouling, another reason could be the way the inlet guide vanes of the GT compressor were controlled. During part load operation the guide vanes were often opened further to obtain a higher air flow and thus a higher pressure of the ASU feed. However the higher air flow caused a lower HRSG flue gas inlet temperature; thus a lower driving force for heat transfer in the high temperature sections.

Part load operation of the gas turbine has a large influence on the total plant performance. The installation at WAC is a single shaft Siemens V94.2 gas turbine as shown in Fig. 4. The gas turbine thermal efficiency($\eta_{th,GT}$) is closely related with the pressure ratio (r) as shown in Eq. (9)

$$\eta_{th,GT} = 1 - \left(\frac{1}{r}\right)^{\frac{\kappa-1}{\kappa}} r = \frac{p_3}{p_4} \tag{9}$$

κ is the specific heat ratio. When the gas turbine is operating under part load (off-design condition), the inlet mass flow rate and inlet pressure decreases when compared to operation at full load (design condition[46]). Thus the off-design pressure ratio is lower than the design case leading to a lower thermal efficiency of the gas turbine.

Table 4
STEX model validation – process parameters compared with experimental test data. Power output and net efficiency are predicted with less than 3% deviation.

	STEX – test data	STEX – model output		STEX – test data	STEX – model output
Fuel Input			*Gas preparation*		
Input pulverized Coal, kg/s	23.74	23.74	Nitrogen temperature, °C	58.10	59.00
LHV, MJ/kg	19.59	19.59	Nitrogen pressure, bar	13.01	13.01
Thermal input, MW	465.00	465.00	Nitrogen mass flow, kg/s	38.32	38.00
Gasifier			Saturator syngas outlet temperature, °C	119.54	119.62
Outlet presssure, bar	24.90	24.90	Preheater syngas outlet temperature, °C	277.00	292.41
Outlet temperature, °C	1515.00	1515.00	*Powerblock*		
Oxygen mass flow, kg/s	14.73	14.74	Air compressor discharge, bar	9.40	9.05
Moderation steam, kg/s	1.18	1.18	Air bleed, kg/s	61.90	61.90
Quench gas recycle, kg/s	58.70	52.42	Combustion chamber pressure, bar	9.15	8.78
Temperature quench gas, °C	272.00	243.40	HP Steam turbine inlet pressure, bar	85.80	92.93
Quench pressure after compres., bar	24.30	24.90	HP Steam turbine outlet pressure, bar	26.60	27.82
Syngas cooler			HP Turbine inlet temperature, °C	478.70	473.71
Syngas inlet temperature, °C	845.00	820.00	HP Turbine Outlet temperature, °C	318.20	311.92
Syngas outlet temperature, °C	267.00	229.40	HP Steam mass flow, kg/s	64.70	65.64
HP steam to HRSG, kg/s	37.40	36.82	IP Steam turbine inlet pressure, bar	25.70	23.82
HP steam to HRSG: Temperature, °C	346.20	363.90	IP Steam turbine outlet pressure, bar	3.53	3.59
IP steam to HRSG, kg/s	11.06	15.60	IP Turbine inlet temperature, °C	461.00	463.50
IP steam to HRSG: Temperature, °C	347.40	321.69	IP Turbine Outlet temperature, °C	207.80	227.34
LP steam: Pressure, bar	9.60	9.00	IP Steam mass flow, kg/s	73.40	80.13
LP steam: Temperature, °C	173.40	175.36	LP Steam turbine inlet pressure, bar	4.57	3.59
LP steam: Mass flow, kg/s	7.50	4.34	*HRSG*		
Cyclones			HP Steam raising mass flow, kg/s	27.20	28.80
Outlet temperature syngas, °C	261.00	229.39	HP Superheater outlet temperature, °C	484.30	476.34
Wash columns			HP Superheater outlet pressure, bar	88.60	97.93
Outlet mass flow syngas, kg/s	35.70	40.93	LP Steam raising mass flow, kg/s	6.10	4.15
Pressure syngas, bar	22.50	24.52	LP Superheater outlet temperature, °C	232.30	233.25
HCN/COS reactor			LP Superheater outlet pressure, bar	4.75	3.59
Outlet temperature syngas, °C	187.30	191.80	*Power output*		
Outlet pressure, bar	20.70	21.72	Gross Power output, MW	199.60	204.85
H_2S absorber			Auxiliary load, MW	30.56	31.82
Outlet temperature syngas, °C	40.00	40.00	Net Power output, MW	169.10	173.02
Mass flow syngas, kg/s	33.50	33.14	Net efficiency, %	36.37	37.20

Table 5
STEX model validation – comparison of syngas composition (dry basis) after washcolumns and after gas cleaning with experimental test data.

%	After washcolumn		After gas cleaning	
	Test data	Model output	Test data	Model output
H_2	27.53	26.13	28.40	26.97
N_2	7.34	6.22	7.58	6.42
AR	0.98	0.82	1.01	0.84
CH_4	0.01	0.00	0.00	0.00
CO	54.72	57.13	56.22	58.96
CO_2	9.29	9.41	6.79	6.80
COS	0.01	0.02	0.00	0.00
H_2S	0.12	0.25	0.00	0.00
Total	100.00	100.00	100.00	100.00

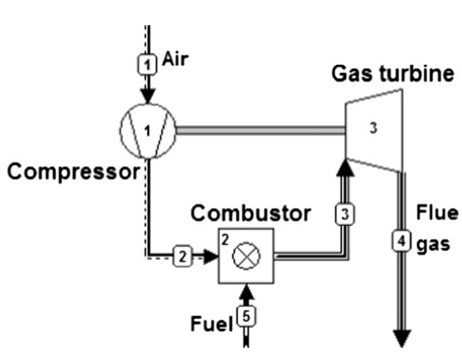

Fig. 4. Schematic - single shaft gas turbine as installed at the Willem-Alexander Centrale.

Due to a reduction in the turbine inlet temperature (T_3), the temperature of heat addition to the steam cycle is also lower compared to the design case. This results in a lower thermal efficiency and reduced performance of the steam cycle. A lower thermal efficiency of the gas turbine and steam cycle ultimately leads to a reduced total plant performance in the considered off-design case. This trend is also predicted by Traupel's formula (Eq. (5)) and can be clearly seen with the modeling results and test data.

Table 5 compares the syngas composition (on a dry basis) with test data at two specific points, after the wash column and after gas cleaning (H_2S removal). The gas composition after gas cleaning has been estimated by NUON-Vattenfall based on the composition measured after the wash columns. The developed model predicts the gas composition reasonably well at both locations. Molar fractions of H_2, N_2 and Ar are slightly underpredicted by the model while CO and CO_2 mole fractions are slightly higher compared to the measured values; CO_2 content though matches well with test data after gas cleaning. During real operation, more N_2 is added in the system which could not be taken into account in the model due to unavailability and uncertainty in the test data. Process engineers at the plant have also pointed out that the nitrogen transport gas measurement could be too low. Overall, the N_2 content does not have a major effect on plant performance. The higher (about 5%) CO content in the model could be due to a slightly different water gas shift (WGS) reaction temperature and fuel composition. This leads to a higher CO_2 and H_2 mole fraction in the syngas. Uncertainty exists in the fuel composition; particularly the oxygen content as this was calculated by difference. Also on a mole basis, the LHV for CO and H_2 are comparable, hence a change in the water gas shift reaction temperature would not have a drastic effect on the syngas LHV. The very small deviations could also be due to a slightly different gasifier temperature and different water gas shift effect or combinations of both during real operation, as both these temperatures were estimated.

The WAC IGCC power plant is based on the Shell Coal Gasification Process which is an entrained flow gasifier operating at high temperatures of about 1500 °C. The coal and biomass feed is pulverized to fine particles. With a sufficient residence time and high temperatures the tar yield was negligible [58]. Process engineers at WAC have not observed the presence of tar components and problems relating to tar deposition were also not encountered in the gas cleaning/cooling units.

Validation of the model in both design [46] and off-design mode makes it well suited for plant performance prediction with fuel blends containing 70% torrefied woodpellets. The model calculations and independent calculations by Nuon/Vattenfall show that a net output of 230 MW is not achievable with co-gasification of steam exploded woodpellets. Due the lower LHV of steam exploded woodpellets compared to coal, the fuel mass flow to the gasifier had to be increased in order to maintain the same electrical output. There were three main constraints which had to be considered: the capacity of the powder coal feed system, the ASU oxygen production capacity and the heat input to the syngas cooler. The capacity of the powder coal feeding system was certainly insufficient to operate the plant at 230 MW electrical output using a fuel mixture with 70% steam exploded woodpellets. But there was a hardware modification foreseen which could have solved this bottleneck. The oxygen production capacity was not of major concern as the oxygen requirement was more or less proportional to the thermal input to the gasifier. Even at maximum plant load using a fuel mixture with 70% steam exploded wood pellets, the oxygen requirements would stay within the maximum production capacity of the ASU. The real bottleneck was the maximum cooling capacity of the syngas cooler. In practice this was limited to appr. 92 MW. Because of the lower cold gas efficiency and thus a higher heat load to the syngas cooler, the maximum cooling capacity of the syngas cooler was already exceeded at a plant load well below 230 MW. Increase of the cooling capacity was impossible without major plant modifications. On this basis, NUON-Vattenfall decided to investigate possibilities to co-gasify torrefied woodpellets. Due to lower H/C and O/C ratios compared to steam exploded wood pellets, the cold gas efficiency would not reduce significantly and it was expected that the heat input to the syngas cooler would stay below 92 MW at the desired plant load. The validated model was thus used to predict the plant output and performance for two fuel blends containing torrefied woodpellets (TORR-low and TORR-high cases). The next section describes the prediction results for the TORR-low and TORR-high cases.

4.2. Performance prediction with torrefied woodpellets

Model calculations with steam exploded pellets show that it is not possible to achieve a net output of 230 MW with a constraint of the maximum SGC heat transfer. Based on NUON-Vattenfall requirements, prediction results were obtained using the validated model for higher LHV fuel blends consisting of torrefied pellets. Table 6 shows the output parameters for the TORR-low and TORR-high cases.

A net output of 226.5 MW is achieved for the TORR-low case with maximum SGC heat transfer. It is immediatly seen that in order to achieve the target of 230 MW, a higher LHV fuel mix is required. The TORR-high case gives a net output of about 240 MW with a net efficiency of 41.60%. Plant performance during real operation is expected to be lower than the predicted performance as explained in the previous section. For both cases, the total SGC heat transfer was within a safe limit of 91 MW.

Parametric evaluation from Table 6 shows that less steam is added during gasification than the STEX case. This steam was added primarily because it had a beneficial effect on fines concentration and stability in the slag bath circulation flow. The gas turbine inlet temperature also increases to 1018 °C approaching a value close to the design case model [46]. A higher auxiliary load is also calculated for the cases with torrefied pellets. This is due to additional power requirements by the N_2 and O_2 compressors in the ASU. Since quantitative data was not readily available, a constant value (as shown in Table 3) has been used for the fuel milling, tracing and miscellaneous power consumption. Milling of torrefied pellets in practice would require lower power than steam exploded pellets. Table 7 shows the syngas composition for both the cases after the washcolumn and gas cleaning unit. A higher H_2 and CO content is observed in the syngas in comparison with the STEX case. The CO_2 content is lower, accordingly. With a lower H/C and O/C ratio compared to the STEX case, the fuel mix composition in the TORR-high and TORR-low cases are more similar to the design case fuel composition.

Based on this analysis, it is concluded that a net output of 230 MW could be achieved at the Willem-Alexander Centrale utilizing 70% high LHV fuel blend with torrefied pellets, fulfilling the aforementioned plant constraints. As aging and fouling aspects have not been taken into account in the model, in practice with a higher auxilliary load, a slightly lower net power output is expected.

4.3. Exergy analysis

Exergy analysis is an important tool in thermodynamic evaluation of systems to identify the true thermodynamic losses [59]. Cycle-Tempo offers a possibility to calculate exergy flows, exergy losses and exergy efficiencies as an aid to carry out second law analyses. The exergy of matter is calculated as the reversible (maximum) work derived by bringing matter in thermomechanical and chemical equilibrium with the reference environment. Thus the exergy of matter is calculated as a sum of the thermomechanical and chemical exergies. In principle, the kinetic and potential exergies are also included but since they do not usually change significantly, this is neglected in the calculation. In order to quantify the exergy loss; the exergy of matter, exergy of heat (in case of heat transfer to/from the environment) and exergy of work (in case of work generation/consumption) is calculated for all streams/components [59]. The exergy loss is then calculated as the difference between the incoming and outgoing exergy. The functional exergy efficiency is calculated according to Eqn. (10), where Ex_{source}, $Ex_{product}$ and Ex_{loss} represent the exergy source, product exergy and exergy losses respectively:

$$\eta_{ex} = \frac{Ex_{product}}{Ex_{source}} = \frac{Ex_{source} - Ex_{loss}}{Ex_{source}} \quad (10)$$

Table 8 shows the exergy efficiencies for the three cases considered in this study. Operation with high LHV torrefied pellets gives the highest exergy efficiency, comparable to the base case exergy efficiency [46]. Figs. 5 and 6 show the exergy flow diagram for the STEX and TORR-high cases respectively illustrating the exergy losses due to various operations in the plant.

With both cases, exergy losses during gasification and combustion contribute largely to the irreversibilities in the system (about 37–38% of the total exergy loss). Exergy losses due to syngas cooling, cleaning and saturation are relatively small while losses in the combined cycle and ASU are approximately 12–13%. The percentage exergy loss due to gasification is slightly higher with co-gasification when compared to the design case. This is attributed to the higher H/C, O/C ratios in the fuel mix and the lower cold gas efficiency. A slight reduction is observed in the percentage of exergy loss (relative) in the GT combustor; mostly due to the lower syngas LHV compared to the design case. Comparison of results from the exergy flow diagrams between STEX and TORR-high also

Table 6
Comparison of model process parameters for TORR-low and TORR-high cases. Operation with a high LHV fuel blend is essential to achieve the desired power output.

	TORR-low	TORR-high		TORR-low	TORR-high
Fuel input			*Gas preparation*		
Input pulverized Coal, kg/s	24.21	24.21	Nitrogen temperature, °C	59.00	59.00
LHV, MJ/kg	22.87	23.82	Nitrogen pressure, bar	12.01	13.50
Thermal input, MW	553.68	576.68	Nitrogen mass flow, kg/s	48.00	51.50
Gasifier			Saturator syngas outlet temperature, °C	120.00	120.00
Outlet presssure, bar	23.90	23.90	Preheater syngas outlet temperature, °C	298.40	300.60
Outlet temperature, °C	1500.00	1500.00	*Powerblock*		
Oxygen mass flow, kg/s	18.20	18.45	Air compressor discharge, bar	10.44	10.80
Moderation steam, kg/s	0.50	0.50	Air bleed, kg/s	76.43	77.50
Quench gas recycle, kg/s	58.37	58.92	Combustion chamber pressure, bar	10.17	10.53
Temperature quench gas, °C	248.26	248.67	Gas Turbine inlet temperature, °C	994.90	1018.00
Quench pressure after compres., bar	23.90	23.90	HP Steam turbine inlet pressure, bar	111.10	115.80
Syngas cooler			HP Steam turbine outlet pressure, bar	32.36	33.45
Syngas inlet temperature, °C	820.00	820.00	HP Turbine inlet temperature, °C	489.99	495.59
Syngas outlet temperature, °C	233.26	233.52	HP Turbine Outlet temperature, °C	320.71	324.06
HP steam to HRSG, kg/s	43.62	44.67	HP Steam mass flow, kg/s	78.30	81.40
HP steam to HRSG: Temperature, °C	362.69	362.75	IP Steam turbine inlet pressure, bar	28.36	29.45
IP steam to HRSG, kg/s	16.58	16.59	IP Steam turbine outlet pressure, bar	4.13	4.36
IP steam to HRSG: Temperature, °C	331.90	333.50	IP Turbine inlet temperature, °C	484.10	491.70
LP steam: Pressure, bar	9.00	9.00	IP Turbine Outlet temperature, °C	238.40	245.70
LP steam: Temperature, °C	175.36	175.36	IP Steam mass flow, kg/s	94.27	97.36
LP steam: Mass flow, kg/s	5.19	5.28	LP Steam turbine inlet pressure, bar	4.13	4.32
Cyclones			*HRSG*		
Outlet temperature syngas, °C	233.25	233.50	HP Steam raising mass flow, kg/s	34.67	36.75
Wash columns			HP Superheater outlet temperature, °C	492.40	497.90
Outlet mass flow syngas, kg/s	46.90	47.50	HP Superheater outlet pressure, bar	116.10	120.80
Pressure syngas, bar	23.52	23.52	LP Steam raising mass flow, kg/s	4.34	4.39
Outlet temperature syngas, °C	139.80	136.10	LP Superheater outlet temperature, °C	246.30	249.30
HCN/COS reactor			LP Superheater outlet pressure, bar	4.13	4.36
Outlet temperature syngas, °C	192.00	192.00	*Power output*		
Outlet pressure, bar	23.52	20.72	Gross Power output, MW	261.40	277.50
H_2S absorber			Auxiliary load, MW	34.93	37.10
Outlet temperature syngas, °C	40.00	40.00	Net Power output, MW	226.50	240.40
Mass flow syngas, kg/s	39.43	40.81	Net efficiency, %	40.90	41.69

Table 7
Syngas composition (dry basis) after washcolumns and after gas cleaning for TORR-low and TORR-high cases as predicted by the developed off-design model.

Mole (%)	After washcolumn		After gas cleaning	
	TORR-low	TORR-high	TORR-low	TORR-high
H_2	26.60	26.54	27.18	27.01
N_2	5.97	5.80	6.10	5.90
Ar	0.85	0.83	0.86	0.84
CH_4	0.00	0.00	0.00	0.00
CO	59.73	61.27	61.03	62.36
CO_2	6.74	5.46	4.82	3.88
COS	0.01	0.01	0.00	0.00
H_2S	0.09	0.08	0.00	0.00
Total	100.00	100.00	100.00	100.00

Table 8
Exergy output and exergy efficiency for various cases – TORR-high gives the highest exergy efficiency.

Parameter	STEX	TORR-low	TORR-high
Exergy input (MW)	510.50	598.22	620.72
Exergy gross output (MW)	204.84	261.44	277.57
Exergy net output (MW)	173.02	226.51	240.46
Exergy efficiency (%)	33.89	37.86	38.73

indicates the thermodynamic advantage of using torrefied biomass. Fraction of exergy losses due to the various operations are lower with the TORR-high case. A lower O/C and H/C ratio in the fuel mix helps in reducing irreversities due to gasification. The results obtained in this study also show similar trends obtained with the theoretical modeling study carried out by Prins et al. [60].

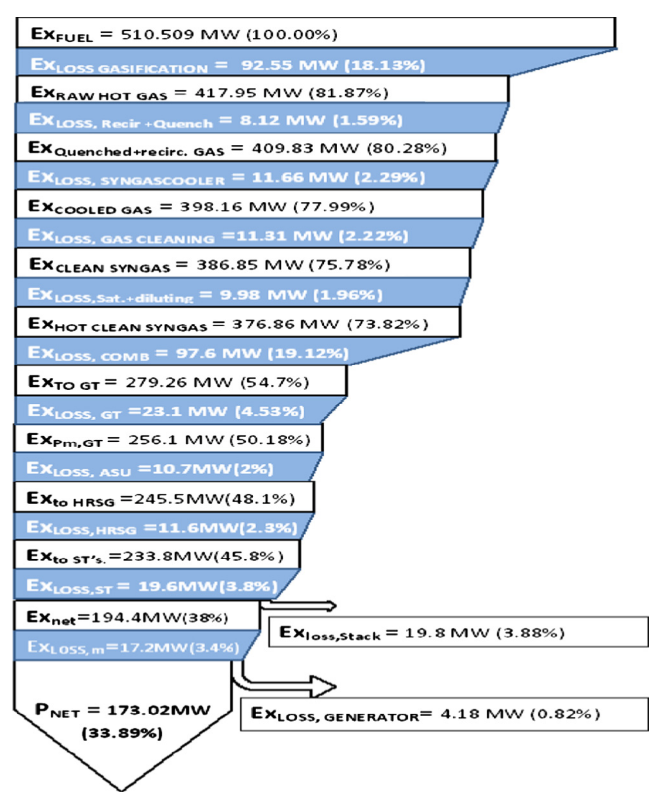

Fig. 5. Exergy flow diagram for STEX case – losses during gasification and combustion are the highest.

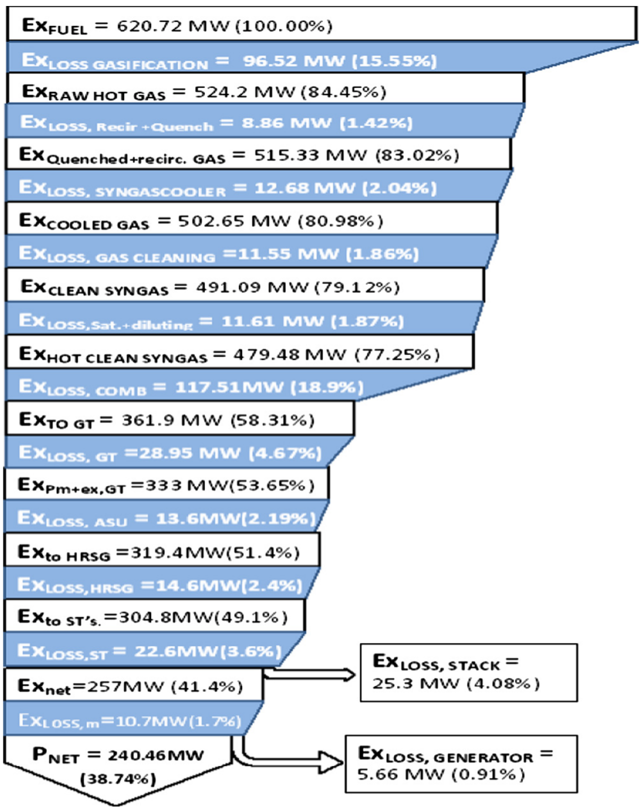

Fig. 6. Exergy flow diagram for TORR-high case – exergy losses are lower compared to the STEX case.

5. Conclusions and future work

First of its kind experimental demonstration and test data has been presented for a high percentage (70%) biomass co-gasification test using steam exploded wood pellets at the 253 MW_e Willem-Alexander Centrale IGCC plant in Buggenum, the Netherlands.

- Presented test data serves as a comprehensive, reliable and first of its kind literature data source for large scale-high percentage biomass co-gasification in IGCC plants.
- The steady state model validation study reveals that inspite inescapable sources of inconsistencies, such models can be effectively utilized to predict the plant performance with a relatively high accuracy (within 3% relative deviation).
- Fouling in the HP section of the SGC has been identified as the main reason for the deviations in the prediction of IP/LP steam flows.
- From the model calculations, it is also concluded that in order to achieve a net output of 230 MW without extensive plant modifications, a high LHV fuel blend with a relatively high quality coal and torrefied pellets is essential. A net electrical efficiency of 41.5% is predicted for this case.
- Gasification and combustion have been identified as the processes with the highest exergy destruction indicating a potential for further optimization of the system.

The demonstration of such a high percentage biomass co-gasification test at a large scale power plant shows that existing coal based IGCC plants can be operated with an increasing percentage of biomass in the fuel mix without extensive plant modifications. Such demonstrations are also of vital significance for the further development of low emission/carbon neutral plants. The developed off-design models could serve as a strong platform and play an instrumental role to plan real plant operation with various biofuels and to carry out studies involving novel carbon capture technology integration, retrofitting with advanced technologies (for eg. with high temperature fuel cells) and IGCC plant optimization.

5.1. Future work

Irreversibilities occurring during combustion can be significantly reduced by the (partial) replacement with solid oxide fuel cells (SOFCs) due to the direct electrochemical conversion of syngas. Studies carried out within our research group have indicated that significantly high efficiencies can be achieved by integrating solid oxide fuel cells with gasification based plants. Further theoretical research on thermodynamic aspects of integrating SOFCs into IGCC systems is a subject of ongoing research in our team.

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Appendix A. Feedstock composition and heating values

NUON/Vattenfall carried out laboratory tests to analyze the coal and biomass feedstocks. The ultimate and proximate analysis of the different feedstock has been shown in Table A.1. Different types of coal (from different countries, different composition) and pellets were obtained from various suppliers to carry out these large scale tests. Fuel blends with the desired coal to biomass ratio were obtained by utilizing improvized processes on the old existing equipment (designed for coal) at the site. Inconsistencies do exist to a limited extent in the obtained final compositions due to this and also from multiple laboratory tests. This unquantifiable uncertainty is unavoidable for such a large scale test and hence is acceptable in view of the authors.

Table A.1
Raw fuel composition and lower heating values for the various coal and biomass types.

	AUS-I coal	Columbian coal	Steam exploded pellets	Torrefied pellets	South African coal
Ultimate analysis					
C	64.99	50.06	54.20	62.00	64.45
H	5.28	3.36	5.97	5.56	3.56
N	1.57	1.32	0.20	0.31	1.60
O	15.02	8.98	39.11	31.61	16.70
S	0.94	0.99	0.01	0.01	0.49
Cl	0.00	0.015	0.004	0.004	0.004
Proximate analysis					
Ash (%)	12.20	35.27	0.50	0.50	13.19
Moisture (%)	9.50	13.38	5.06	5.40	9.66
Fixed carbon (%)	47.80	25.70	19.17	31.91	53.45
Volatile matter (%)	30.50	25.65	75.27	62.19	23.70
LHV (MJ/kg)	26.75	20.00	19.32	21.87	24.26

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