UNIVERSIDADE ESTADUAL DE CAMPINAS
FACULDADE DE ENGENHARIA MECÂNICA
COMISSÃO DE PÓS-GRADUAÇÃO EM ENGENHARIA MECÂNICA

Cofiring como Alternativa para Impulsionar a Tecnologia de Gaseificação de Biomassa Integrada a Ciclos Combinados – BIG-CC

Autor: **Mônica Rodrigues de Souza**
Orientador: Arnaldo Walter
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Campinas, 2001
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TESE DE DOUTORADO

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Dedico este trabalho ao meu avô.

"Honest disagreement is often a good sign of progress"

Mahatma Gandhi

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Resumo

SOUZA, Mônica Rodrigues de, *Cofiring como Alternativa para Impulsionar a Tecnologia BIG-CC,* Campinas,: Faculdade de Engenharia Mecânica, Universidade Estadual de Campinas, 2001. 177 p. Tese (Doutorado)

Este trabalho analisou a queima conjunta de gás de biomassa e gás natural em plantas BIG-CC (gaseificação de biomassa integrada a ciclos combinados). A queima conjunta é proposta como alternativa para minimizar as barreiras tecnológicas e reduzir custos, e deste modo impulsionar a disseminação do aproveitamento de biomassa na forma gaseificada. O trabalho pode ser dividido em modelagem de ciclos para cálculo de performance e avaliação econômica. Ciclos combinados de diferentes tipos e capacidades foram modelados utilizando-se parâmetros genéricos para os equipamentos das plantas de geração e hipóteses simplificadoras. Os resultados foram obtidos para o caso com queima de biomassa ou gás natural, assim como para várias razões de mistura. Para caso com queima de gás de biomassa apenas, os resultados foram avaliados levando em conta diferentes estratégias de controle para o uso de gás de baixo poder calorífico, inclusive aquelas esperadas para o longo prazo. Em curto prazo, a estratégia mais simples, o de-rating , que leva a perdas consideráveis de eficiência e potencia poderia ser totalmente evitada com o mistura de gases de 30 a 50% em base energética. Estes ganhos em eficiência e a possibilidade de se aumentar as escalas das plantas levam a benefícios econômicos expressivos tornando a tecnologia BIG-CC competitiva em curto prazo.

Palavras Chave

Queima conjunta (cofiring), Eletricidade a partir da biomassa, BIG-CC.

Abstract

Souza, Mônica Rodrigues de, *Cofiring como Alternativa para Impulsionar a Tecnologia BIG-CC,* Campinas,: Faculdade de Engenharia Mecânica, Universidade Estadual de Campinas, 2001. 177 p. Tese (Doutorado)

This work proposes co-firing of natural gas and biomass gas BIG-CC's. The aim is to reduce technological drawbacks and improve the cost-effectiveness of BIG-CC's in order to encourage the technology in the short-term. This work can be dived in performance modeling and cost-effectiveness evaluation. Combined cycles of different capacities and types have been modeled based on generic parameters and simplifying assumptions. Results were first obtained for the cases burning biomass only, which include long-term strategies. The strategy to be practiced in the short-term due to its simplicity, the de-rating, can be avoided with co-firing. Results showed that shares between 30-50% of natural gas, de-rating could be avoided with significant gains in efficiency and power. The better performance leads to costs reduction and the mixture with natural gas allows better economies of scales. As a result, co-firing can improve the cost-effectiveness of BIG-CC's and eventually make biomass power competitive in Brazil.

Key Words

Co-firing, electricity from biomass, BIG-CC

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Capítulo 1

Introdução

1.1 Considerações iniciais

O termo "energia de biomassa" é usado para descrever a energia obtida de matéria orgânica, de origem vegetal ou animal (Bauen, 2000). As fontes de biomassa são, portanto, extremamente diversificadas, sendo as mais comuns as plantações energéticas e os resíduos agrícolas, florestais e aqueles provenientes da criação de animais. O conceito é estendido a resíduos orgânicos industriais e urbanos, bem como a resíduos da construção civil (madeira). O crescente interesse relativo à biomassa proveniente das plantas está associado à sua utilização como combustível com emissões neutras, ou bastante pequenas, de dióxido de carbono. Se as etapas básicas da produção de biomassa, tais como o cultivo, o manejo e a colheita forem realizadas de forma sustentável, a liberação do carbono na etapa de uso dos bio-combustíveis será compensada por sua absorção durante o crescimento das plantas (Hall & House, 1995). A utilização de biomassa em substituição a combustíveis fósseis evita não só as emissões de dióxido de carbono, mas também as emissões de outros poluentes, como óxidos de enxofre.

Considerando exclusivamente a geração de energia elétrica, ao contrário das outras fontes renováveis de energia, a biomassa pode ser utilizada em plantas térmicas similares às já existentes, sem grandes mudanças na operação ou na forma de entrega de eletricidade à rede. Como o recurso energético não é intermitente, embora muitas vezes sazonal, sua utilização pode ser contínua e programada. Outro benefício potencial é a criação de empregos, particularmente em áreas rurais, o que pode ajudar no combate à migração para as grandes cidades nos países em desenvolvimento. A criação de empregos é também importante em países industrializados e o cultivo de biomassa poderia levar a uma utilização mais racional de terras ociosas na Europa e na América do Norte. Nos Estados Unidos, por exemplo, projeções indicam que em torno de 52 milhões de hectares poderão estar ociosos em 2030 como resultado de ganhos em produtividade (Consonni e Larson, 1996).

De acordo com o *Biomass Users Network* o consumo atual de biomassa é estimado em 14% em relação a toda a energia consumida no mundo. Nos países em desenvolvimento a parcela é consideravelmente maior do que nos países industrializados – 35% e 3%, respectivamente (Van den Broek, 2000). A biomassa é tradicionalmente um combustível associado à pobreza e ao baixo desenvolvimento tecnológico, mas o seu papel como energético moderno tem aumentado (Bauen, 2000). Este aumento está relacionado a uma preocupação crescente com a segurança do suprimento de energia, o esgotamento dos recursos, além de questões relacionadas a preços e ao meio ambiente. A nível global, o foco do problema ambiental é a emissão de gases causadores do efeito estufa.

1.2 O consumo de energia e as mudanças climáticas globais

O problema conhecido como efeito estufa e seu contínuo aumento, também referenciado como mudanças climáticas globais, foi pela primeira vez associado claramente à concentração de dióxido de carbono na atmosfera em 1895, em trabalho do Prêmio Nobel Sueco Svente Arrenhuis, mas só após sessenta anos seus estudos começaram a ser aprofundados (Phylipsen, 2000). Hoje sabe-se que o aumento da concentração de outros gases na atmosfera, tais como metano, óxidos de nitrogênio, ozônio e CHCs, também colabora para com o aquecimento global. Entre os gases que causam o efeito estufa o CO_2 não é o mais potente, mas são suas emissões as responsáveis pela maior parcela do aquecimento devido à quantidade emitida e à extensão de seu ciclo de vida. Estima-se que 57% do efeito estufa está associado ao uso de energia, sendo que dessa parcela 54% correspondem à queima de combustíveis fósseis (Kemp, 1994).

A seriedade do problema foi publicamente reconhecida em 1979, na primeira conferência mundial sobre o tema, realizada em Genebra. As pesquisas realizadas ao longo das décadas de 60-80 resultaram em ações concretas, como a realização da segunda Conferência sobre Mudanças Climáticas, em 1990. A 45ª Assembléia das Nações Unidas estabeleceu então o Painel Inter-Governamental sobre Mudanças Climáticas - IPCC[1], com o objetivo de aprofundar os estudos sobre o tema e propor soluções para a mitigação do problema. O primeiro relatório científico do IPCC foi de tal forma incisivo sobre as causas e consequências do aquecimento global que acabou por influenciar a definição dos princípios da Convenção Internacional em Mudança Climática (Phylipsen, 2000), cuja versão final foi assinada por 154 países durante a Conferência das Nações Unidas para Meio Ambiente e Desenvolvimento, no Rio de Janeiro, em 1992 (ONU, 1992).

Os governos signatários da Convenção se comprometeram a atingir o seu objetivo último, ou seja, "a estabilização da concentração dos gases causadores do efeito estufa na atmosfera em um nível tal que previna a perigosa interferência humana sobre o sistema climático". A Convenção enfatizou que os países desenvolvidos são os principais responsáveis pelas emissões atuais e históricas, e devem liderar ações voltadas ao combate das mudanças climáticas. Assim, os países industrializados devem estabilizar as suas emissões em níveis determinados pela Convenção, denominados compromisso de redução de emissões. A prioridade para países em desenvolvimento deve ser o seu próprio desenvolvimento social e econômico.

Foi estabelecido na Rio 92 que os compromissos de redução das emissões dos gases causadores do efeito estufa só têm validade quando um número mínimo de países – 55, cujas emissões somem pelo menos 55% das emissões descritas no Anexo I[2] - ratificarem a Convenção.

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[1] Intergovernmental Panel on Climate Change.

[2] Países industrializados responsáveis pelas maiores emissões históricas e atuais.

Ficaram definidos na Rio 92 apenas princípios gerais, tendo sido postergado para as Convenções Climáticas subsequentes a definição das metas e dos mecanismos de cumprimento.

Foi apenas em Kyoto, no Japão, em 1997, que houve avanços concretos no tema. Após duas semanas de reunião ficou acordado que os países industrializados devem reduzir até 2008-2012, em 5,2%, em média, suas emissões em relação àquelas verificadas em 1990. Para que essas metas pudessem ser alcançadas mais facilmente ficou definido que os países do Anexo I poderiam fazer uso dos chamados mecanismos flexíveis, que incluem créditos de carbono comprados de outros países, a transferência de tecnologias que resultem em menores emissões[3] ou, ainda, a plantação e proteção de florestas (Phylipsen, 1999).

Os países industrializados podem atingir as metas de redução de emissões de CO_2 através de projetos implementados em conjunto com outros países industrializados (JI[4]) ou em países em desenvolvimento, através dos projetos de Mecanismo de Desenvolvimento Limpo (MDL[5]). De acordo com o Protocolo de Kyoto, além de contribuir com o compromisso de redução de emissões dos países industrializados, o MDL deve garantir o desenvolvimento sustentável dos países onde os projetos são implementados (ONU, 1997). O conceito de desenvolvimento sustentável é vasto, tendo sido definido pela Comissão de Meio Ambiente e Desenvolvimento como sendo "o desenvolvimento que assegura as necessidades das gerações do presente sem comprometer a habilidade das futuras gerações em satisfazer as suas próprias necessidades" (WCED, 1987). O desenvolvimento sustentável é entendido como um conceito multidimensional, que envolve o bem estar individual, igualdade de oportunidades, segurança e, também, a manutenção de uma condição saudável para humanos, animais e plantas, protegendo a biodiversidade e evitando riscos ambientais inaceitáveis (Van den Broek, 2000).

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[3] Por exemplo, aumento da eficiência energética, substituição de combustíveis fósseis, investimento em projetos de fontes renováveis de energia.

[4] Joint Implementation.

[5] Em Inglês, Clean Development Mechanism – CDM.

O Protocolo de Kyoto não foi ratificado em 1997 e, portanto, não entrou em vigor naquela oportunidade. Outras Conferências das Partes (COP) foram realizadas com esse propósito, mas fracassaram. A Sexta delas, realizada em Haia, Holanda, em 2000, foi suspensa e só finalizada em Julho de 2001 em Bonn, na Alemanha. Houve finalmente um acordo que garante a ratificação do Protocolo de Kyoto, mas sem a adesão dos EUA. Para que fosse possível obter a adesão do Japão, do Canadá e da Austrália, atingindo o limite de 55 países responsáveis por pelo menos 55% das emissões, as resoluções de Kyoto tiveram de ser renegociadas. A aceitação de que os países contabilizem como emissões reduzidas o CO_2 retirado da atmosfera por florestas em crescimento é o ponto mais polêmico para os ambientalistas.

O que se entende como excessiva flexibilização do Protocolo pode resultar na perda de importância dos Mecanismos de Desenvolvimento Limpo, e simplesmente eliminar a oportunidade de captação de recursos para a viabilização de projetos de fomento às fontes renováveis de energia nos países em desenvolvimento. De qualquer forma, mesmo com todas as ressalvas, a ratificação do Protocolo de Kyoto é apenas o primeiro passo e ainda é muito cedo para se fazer qualquer avaliação do futuro dos acordos internacionais relativos a mudanças climáticas globais.

1.3. O uso energético da biomassa

A população dos países em desenvolvimento continua a crescer e, projeta-se, em torno de 2050 90% da população mundial residirá nos países não industrializados (Hall & House, 1995). Devido à crescente industrialização e às melhorias nos padrões de consumo nesses países, estima-se maior intensidade no uso de energia e, em especial, de eletricidade. Alguns estudos indicam que as taxas de crescimento do consumo de eletricidade, em alguns países, podem chegar a até 10% ao ano nos próximos 20-30 anos (Walter et al., 2000a). Na hipótese dos países em desenvolvimento viabilizarem o aumento da oferta elétrica com uso de carvão mineral, ou de outros combustíveis fósseis, as emissões de dióxido de carbono crescerão drasticamente e os efeitos sobre o aquecimento global serão de grande magnitude. O uso moderno da biomassa, baseado na produção de eletricidade e na conversão dos recursos sólidos em combustíveis líquidos e gasosos, a partir de sua exploração sustentável, pode contribuir para com o desenvolvimento de muitos países e, ao mesmo tempo, para com a minimização dos impactos ambientais globais (Hall & House, 1995; Walter et al., 2000a).

O Brasil é um país líder na utilização de insumos energéticos renováveis, que contribuíram em seu conjunto com cerca de 40% do suprimento energético primário do país em 1999. Mais do que 90% da energia elétrica consumida é gerada em hidroelétricas, o que contribuiu em 1999 com cerca de 15% do suprimento primário. A biomassa contribuiu naquele ano com cerca de 27% do suprimento energético primário, sendo 13,4% provenientes dos produtos da cana de açúcar (álcool e bagaço), 11,6% provenientes da madeira (lenha e carvão vegetal) e aproximadamente 2% de outras biomassas, principalmente resíduos agrícolas e licor negro (MME, 2000).

O consumo de bagaço de cana representou em 1999 7,5% do consumo energético total do país. Entre as biomassas, a contribuição do bagaço foi de quase 38%. Entre os produtos da cana a contribuição do bagaço é cerca de 2,5 vezes superior à do etanol, tendo sido da ordem de 780 PJ em 1999 (MME, 2000). O bagaço de cana é quase todo ele consumido nas próprias indústrias sucro-alcooleiras onde é empregado na geração de vapor e, seqüencialmente, na produção de potência mecânica e elétrica. O vapor de escape das turbinas atende a demanda térmica dos processos produtivos de açúcar e álcool. Os ciclos de cogeração são de contra pressão[6], utilizam caldeiras de baixa pressão e operam apenas no período da safra. Do ponto de vista da produção de potência são bastante ineficientes. Todavia, em praticamente todas as usinas do país a produção de energia elétrica é suficiente para suprir toda demanda do processo industrial, sendo que em algumas poucas há produção de energia elétrica excedente. Em relação à disponibilidade há excedente de bagaço em torno de 10%, que é vendido a outras indústrias, principalmente do segmento alimentício (Walter, 1994).

[6] Só a partir de 2001-2002 haverá sistemas com turbinas de extração-condensação.

Por volta de 65% da produção de cana de açúcar está concentrada no Estado de São Paulo, resultando em grande disponibilidade de bagaço no interior do Estado. Por outro lado, a disponibilidade de biomassa residual da cana pode aumentar significativamente na região nos próximos 10-15 anos. Este incremento será resultado da mudança na legislação local, segundo a qual a prática de colheita da cana com queima deve ser extinta até no máximo 2015, mesmo para terras desfavoráveis à mecanização (Braunbeck et al., 1999). A colheita de cana crua disponibilizará as pontas e folhas da planta, biomassa que poderá ser utilizada como combustível e na produção de energia elétrica.

A extinção das queimadas depende da mecanização da colheita, já que a colheita manual de cana crua é inviável economicamente[7]. A mecanização já é, aliás, uma tendência natural devido aos menores custos em relação à colheita manual pós queima, mas a prática atual tem sido a da colheita mecanizada da cana queimada, e não da cana crua. Enquanto estimativas para os custos da colheita manual da cana crua ficam em torno de R$ 6,00, custos da colheita mecanizada da cana crua chegam a R$ 3,00.(Braunbeck et al., 1999). No final dos anos 1990s estimava-se que a mecanização da colheita da cana crescia a uma taxa de 10% por ano (Macedo, 1999). A colheita de cana crua pode disponibilizar, por safra, em torno de até 1000 PJ[8] de energia contidos em pontas e folhas da planta (Braunbeck et al., 1999). Parte desses resíduos devem ser deixados no campo para controle de ervas daninhas, evitar erosão acentuada do solo e impedir o sobre aquecimento das socas. Ainda existem restrições tecnológicas para a colheita mecanizada, em parte por que as máquinas disponíveis no mercado não operam bem, ou sequer podem operar em solos com alta declividade (Braunbeck et al., 1999). Também existem problemas associados à velocidade de operação, à eficiência do cultivo e ao grau de limpeza da cana colhida. Também existem restrições associadas aos custos iniciais e pressões dos próprios cortadores de cana, que querem preservar o emprego.

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[7] A colheita manual de cana crua é bem mais difícil, lenta e perigosa do que a colheita de cana queimada e, portanto, é mais cara.

[8] Essa estimativa já considera restrições topográficas à colheita mecanizada, assim como a necessidade de deixar parte das pontas e folhas nas plantações.

As pontas e folhas podem ser removidas da cana no ato da colheita ou, ainda, após a colheita, em estações de limpeza ou na própria usina. A experiência adquirida até então com a colheita de cana crua não permite definir qual método de colheita e coleta de resíduos é mais viável economicamente. Contudo, existem vantagens associadas aos métodos de colheita que deixam os resíduos no campo para posterior coleta desses em fardos. Essas vantagens são, por exemplo, a armazenagem dos fardos no campo e a redução do volume transportado (Bauen, 2000).

1.4 A tecnologia BIG-GT

As instalações termelétricas convencionais a vapor que utilizam biomassa têm eficiência entre 15-20%, com custos da eletricidade gerada, na Europa e nos EUA, estimados entre US$ 65-80/MWh (Babu, 1995). São, portanto, a menos de situações particulares, pouco competitivas em relação às alternativas convencionais de geração elétrica. A eficiência de tecnologias avançadas para geração de eletricidade baseadas na gaseificação da biomassa pode chegar a 40-45%, isso mesmo em plantas de pequena-média escala (e.g., 25-30 MW) (Faaij, 1997; Consonni & Larson, 1996). A tecnologia de referência, que ainda não está comercialmente disponível, é a denominada BIG-CC (Biomass Integrated Gasification/Combined Cycle), que é uma derivação da designação BIG-GT (Gas Turbine), mais usual. Estes sistemas são conceitualmente similares aos sistemas IGCC (Integrated Gasification/Combined Cycle) que utilizam carvão mineral e que já são comerciais, embora pouco competitivos. Como a biomassa é mais reativa do que o carvão, acredita-se que possam ser alcançadas vantagens em função da maior eficiência de gaseificação a menores temperaturas (Consonni & Larson, 1996).

Em uma instalação BIG-CC a biomassa deve ser inicialmente tratada e seca, sendo então encaminhada para a gaseificação. A gaseificação pode ser tanto pressurizada quanto atmosférica. Um gaseificador pressurizado pode produzir gás a pressão adequada para a aplicação direta em turbinas a gás, eliminando o alto consumo na compressão do gás combustível e permitindo maior eficiência de toda a instalação. Entretanto, existem maiores dificuldades para a gaseificação pressurizada e os sistemas de alimentação a alta pressão, por exemplo, ainda não são comerciais (Bain et al., 2000). O gás combustível produzido precisa então ser limpo, para a remoção de contaminantes e partículas, o que deve ser feito a frio no caso dos sistemas com gaseificação atmosférica em função da posterior compressão para alimentação da turbina. Nos caso dos sistemas com gaseificação pressurizada um desafio adicional é a limpeza do gás a quente. O gás combustível é queimado na turbina e os gases de exaustão são empregados na geração de vapor, permitindo a produção de potência adicional em um ciclo a vapor. Os gases de escape da caldeira de recuperação podem ser finalmente empregados na secagem da biomassa. Um esquema simplificado de um sistema BIG-CC é apresentado na Figura 1.

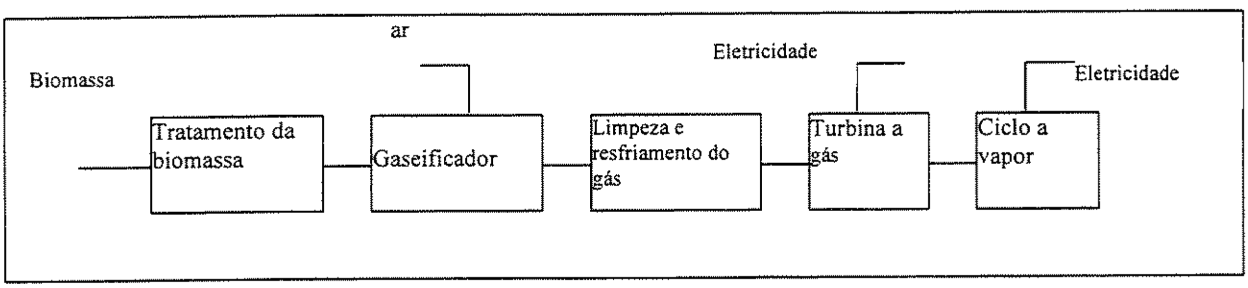

Figura 1.1. Esquema simplificado de um sistema BIG-CC

A tecnologia BIG-CC não está comercialmente disponível, tanto no caso dos sistemas baseados em gaseificação atmosférica quanto pressurizada. Uma unidade de cogeração (calor distrital) baseada na gaseificação pressurizada de resíduos florestais e chips de madeira operou 3.600 horas entre 1996 e 1999 em Värmano, na Suécia[9]. Encerrada a fase de testes a planta foi desativada pois não havia interesse em operá-la comercialmente. A capacidade nominal da unidade correspondia a 6 MW elétricos e 9 MW térmicos, sendo a capacidade de gaseificação equivalente a 82 t/dia. A tecnologia utilizada na gaseificação e limpeza dos gases (a quente, com filtros cerâmicos) é a da Foster Wheeler (Bain et al., 2000).

[9] 3.600 horas de operação do sistema BIG-CC completo; só o gaseificador operou 8.500 horas (Stahl, 2001)

Outra unidade de demonstração da tecnologia está em fase final de construção em Yorkshire, Inglaterra. O projeto ARBRE[10] corresponde a uma unidade BIG-CC com capacidade de produção de 8 MW elétricos e que utilizará resíduos florestais e madeira de rápido crescimento. A tecnologia de gaseificação (a baixa pressão) e de limpeza do gás (a frio, com filtros e posterior lavagem) é a da empresa Sueca TPS.

Outros dois projetos de demonstração da tecnologia estavam previstos para serem construídos na Europa, sendo um deles na Itália[11] e outro na Finlândia[12]. As informações mais recentes dão conta que ambos projetos foram cancelados (Stassen, 2001). Dois projetos de demonstração propostos para os EUA também foram cancelados: a unidade BIG-GT do Havaí, que previa a gaseificação pressurizada de bagaço de cana (tecnologia IGT/Renugas, com limpeza dos gases a quente), e a BIG-CC que seria construída em Minnesota (75 MW elétricos), utilizando resíduos de alfafa e que empregaria gaseificadores pressurizados da Kvaerner/Carbona e filtros cerâmicos para limpeza dos gases (Walter et al., 2000a). Ainda tem continuidade nos EUA o projeto de desenvolvimento da tecnologia de gaseificação indireta a baixa pressão, da FERCO/Batelle, mas a integração da turbina a gás foi suspensa e o gás combustível será simplesmente queimado no geradores de vapor da termelétrica a biomassa já existente (Overend, 2001).

A mesma tecnologia de gaseificação a baixa pressão do projeto ARBRE deve ser empregada na unidade BIG-CC prevista para ser construída no interior da Bahia[13]. A instalação de 32 MW elétricos deve utilizar chips de eucalipto. Já há alguns anos o projeto está parado, em função de dificuldades de financiamento, e a construção sequer teve início. Em princípio, parte do projeto seria financiado pelo GEF (Global Environmental Facility), e parte pelo Banco Mundial.

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[10] Arable Biomass Renewable Energy.

[11] 12,1 MW elétricos, em ciclo combinado, empregando a tecnologia Lurgi de gaseificação atmosférica, limpeza dos gases a frio (filtros e lavagem com água) e utilizando resíduos agrícolas e chips de madeira (Walter et al., 2000a).

[12] Unidade CHP (7,2 MW elétricos e 6,8 MW térmicos), empregando tecnologia de gaseificação pressurizada da U-Gas Renugas e com limpeza dos gases a quente (filtros cerâmicos) (Walter et al., 2000a).

Apesar das dificuldades enfrentadas por todos os projetos de demonstração ainda há otimismo quanto ao futuro da tecnologia. No entanto, os custos de capital da primeira geração dessa tecnologia devem ser bastante elevados quando comparados, por exemplo, com os custos iniciais de plantas termelétricas convencionais que operam com combustíveis fósseis. De acordo com Faaij et al. (1998), os investimentos para a primeira geração de sistemas BIG-CC devem ficar em torno de US$ 2000-4000/kW. Já a TPS prevê que os custos de capital das primeiras unidades comerciais da ordem de 30 MW elétricos devem ficar em torno de US$ 2700/kW (Walter et al., 2000a). Por sua vez, a Sydkraft AB, empresa Sueca que construiu e operou a planta pioneira de Värmano, estima que a próxima unidade similar àquela teria um custo equivalente a 1700 US$/kW (Stahl, 2001).

Como atualmente não há sistemas BIG-CC em operação comercial, não existe efetiva base de dados para previsão dos custos a longo prazo. Entretanto, estudos da TPS avaliam que os custos de capital de uma planta BIG-CC completa com capacidade de 55 MW elétricos podem chegar a US$ 1400/kW em função dos efeitos de aprendizado[14] e dos avanços na tecnologia das turbinas a gás (Walter et al. 2000a). Elliot & Booth (1993) sugerem que para ciclos BIG-CC na faixa de 25 a 30 MW elétricos, baseados em turbinas aero derivativas, os custos unitários de capital poderiam chegar a US$ 1230–1420/kW quando a tecnologia alcançasse escala comercial[15]. Outros estudos apresentam estimativas similares (e.g., Williams & Larson, 1996; Faaij et al., 1998). Com valores dessa ordem, e com níveis de eficiência de produção de energia elétrica pelo menos na faixa de 45-50% (Walter et al., 2000a), essa tecnologia teria condições de ser competitiva.

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[13] Conhecido como BDP – Brazilian Demonstration Project.

[14] Redução dos custos em função da aumento da escala de produção e do aprendizado produtivo e tecnológico.

1.5 Cofiring

Cofiring é um neologismo norte-americano empregado para designar a queima conjunta de dois combustíveis em instalações produtoras de calor (e.g., geradores de vapor), eletricidade (termelétricas), ou ambos (cogeração). O princípio mais bem aceito é o da queima conjunta de biomassa e carvão mineral em indústrias e termelétricas. Tal alternativa é tida como de baixos riscos técnico e econômico e tem sido razoavelmente empregada na Europa e nos EUA (Walter et al., 2000a; Sondreal et al., 2001).

A opção analisada neste trabalho corresponde à queima conjunta de biomassa e gás natural nas turbinas a gás de ciclos combinados, variante que não é comercial e tampouco foi suficientemente estudada até o momento. Em 1995, no National Renewable Energy Laboratory, em Golden, nos Estados Unidos, um estudo foi realizado identificando diferentes arranjos que permitiriam a queima simultânea de biomassa e gás natural na mesma planta, mas não necessariamente a queima simultânea no mesmo equipamento[16] (Spath, 1995).

Em função da percepção das dificuldades tecnológicas e econômicas que terão de ser superadas pelas primeiras unidades comerciais da tecnologia BIG-GT, em função do enorme interesse que envolve a produção de energia elétrica com gás natural em ciclos combinados e, também, em função da grande disponibilidade de biomassa residual da cana de açúcar existente no Brasil, e particularmente no Estado de São Paulo, deu-se início a uma linha de pesquisa cujo objetivo é identificar as condições de viabilização para a geração elétrica a partir dessas duas fontes de energia (biomassa e gás natural).

Alguns estudos corroboram as hipóteses básicas que resultaram na definição da linha de pesquisa acima citada. De Kant & Bodegom (2000) concluem que o cofiring poder ter um importante papel na minimização das barreiras tecnológicas para a utilização do gás resultante da

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[15] No caso, a décima planta comercial.

[16] Por exemplo, em um ciclo combinado, com a queima de gás natural em turbinas a gás e de biomassa na geração de vapor.

gaseificação de biomassa em ciclos combinados, principalmente face à redução de modificações na turbina a gás. Já Horvath & Patel (2000) citam, entre os principais benefícios, a elevação da eficiência na geração de energia elétrica, o baixo custo inicial em relação ao de uma instalação BIG-CC, e a redução dos riscos associados à disponibilidade e à variação dos preços dos combustíveis. A redução dos custos de capital e o aumento da eficiência estariam também relacionados com o aumento da escala das instalações de potência, o que é difícil de se viabilizar em uma planta exclusivamente a biomassa.

Na pesquisa bibliográfica feita neste trabalho nenhuma referência foi encontrada reportando experiências no uso combinado de gás natural e gás de gaseificação de biomassa nas turbinas a gás de ciclos combinados. Contudo, é importante destacar que na Itália existem plantas de cogeração nas quais faz-se a queima conjunta ou complementar de gases residuais de siderurgia com gás natural. Ainda que tenham uma composição diferente esses gases podem ser comparados aos gases derivados da biomassa devido ao baixo poder calorífico, que pode ser tão baixo quanto 3,3 MJ/Nm^3 no caso do gás de alto forno. No caso da planta de Taranto, cuja experiência é reportada por Stambler (1999), a mistura com gás natural permite acentuada elevação da eficiência de geração elétrica e maior estabilidade na operação das turbinas a gás.

Neste trabalho é considerada apenas a opção cofiring que corresponde à queima conjunta de gás natural e gás proveniente da gaseificação de pontas e folhas da cana (e, eventualmente, bagaço excedente) em turbinas a gás de ciclos combinados. Considera-se que esses gases seriam injetados de forma independente nas câmaras de combustão das turbinas. A opção preferencial pelas pontas e folhas deve-se à expectativa de aumento da oferta dessa biomassa e, também, porque as unidades estudadas foram imaginadas como termelétricas, eventualmente afastadas das usinas de açúcar e álcool.

A alternativa de cofiring analisada neste trabalho se justifica principalmente pela possibilidade de melhoria da performance técnica e econômica dos ciclos BIG-CC. Esta opção é especialmente promissora no curto prazo, enquanto a tecnologia ainda está em desenvolvimento e os custos são altos.

O estudo feito segue trabalhos anteriores e preliminares sobre o mesmo tema, nos quais o termo cofiring foi empregado dentro de um contexto mais abrangente, indicando a possibilidade de queima não necessariamente conjunta de biomassa e gás natural, mas também complementar e/ou sequencial. O primeiro trabalho relativo ao tema (Walter et al., 1998) analisou a possibilidade de substituição de gás natural por gás de gaseificação de biomassa em termelétricas a ciclo combinado. A substituição ocorreria assim que a tecnologia de gaseificação e de limpeza dos gases se tornasse madura, e na medida em que o mercado de varejo para o gás natural se desenvolvesse. Um segundo trabalho (Walter et al., 1999) analisou a possibilidade de queima conjunta de gás natural e de gás de gaseificação em turbinas a gás de ciclos combinados e, nesse sentido, é precursor do trabalho desenvolvido nesta tese. Finalmente, em um terceiro trabalho (Walter et al., 2000b) foi analisada a alternativa de queima sequencial em um ciclo combinado: gás natural sendo empregado nas turbinas a gás e biomassa sendo queimada em geradores a vapor convencionais, complementando a geração de vapor viabilizada nas caldeiras de recuperação de calor (HRSG).

1.6 O escopo e estrutura de trabalho

O objetivo central desta tese é avaliar os benefícios da opção cofiring na disseminação a curto prazo de ciclos combinados integrados à gaseificação da biomassa. A preocupação principal do trabalho está na avaliação dos ganhos resultantes da queima conjunta com gás natural, tanto sob o aspecto técnico quanto econômico. A ênfase dada é para os sistemas baseados na gaseificação de biomassa a baixa pressão (quase atmosférica), em razão desta tecnologia ser mais barata, estar mais próxima de um estágio comercial, ser mais adequada para o emprego de biomassa de baixa densidade[17], e apresentar menos barreiras tecnológicas para ser integrada a turbinas a gás.

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[17] Bagaço e pontas e folhas têm menor densidade do que a madeira, por exemplo, e, dessa forma, espera-se mais problemas em sua alimentação em gaseificadores pressurizados.

O trabalho também se justifica pelo contexto atual do setor energético Brasileiro, marcado por uma severa crise de abastecimento elétrico face à excessiva dependência da geração hidrelétrica, pelo aumento da oferta de gás natural e, eventualmente, pela disponibilidade crescente de biomassa residual da cana de açúcar. Muitas usinas termelétricas foram propostas, várias das quais no Estado de São Paulo. Por outro lado, o gasoduto Brasil-Bolívia passa muito próximo das principais áreas produtoras de cana. Assim, a opção cofiring resultaria na diversificação do parque gerador elétrico, poderia reduzir riscos de suprimento de gás natural e biomassa, permitir maior flexibilidade no desenvolvimento de outros mercados para o gás natural, atenuar futuras oscilações de preço do gás[18], além de poder induzir a diversificação e a modernização do setor sucro-alcooleiro. Ainda mais importante pode ser sua contribuição para que a geração elétrica a partir da biomassa seja competitiva, resultando em significativa redução das emissões de CO_2.

O segundo capítulo desta tese trata exatamente do contexto do setor energético brasileiro e avalia a disponibilidade dos resíduos de cana, principalmente no Estado de São Paulo. O objetivo é melhor caracterizar o quadro no qual a opção cofiring pode ser desenvolvida no Brasil. São analisados a atual estrutura do setor elétrico, o suprimento atual e a evolução potencial do mercado para o gás natural, a cogeração no setor sucro-alcooleiro e a disponibilidade de resíduos.

Os capítulos 3 a 5 são apresentados na forma de artigos submetidos à publicação em revistas internacionais. Assim, foram incluídas à tese as versões submetidas, escritas em Inglês e formatadas de acordo com as instruções dos editores. O capítulo 3 corresponde a artigo submetido à revista Applied Energy, no qual analisa-se a viabilidade de uso dos resíduos da cana em ciclo BIG-CC e o impacto das alternativas de adaptação de turbinas a gás, originalmente projetadas para a operação com gás natural, para uso dos gases resultantes da gaseificação de biomassa. As alternativas de adaptação analisadas correspondem essencialmente às estratégias de controle da operação dos compressores das turbinas a gás. A análise é feita do ponto de vista do desempenho das turbinas e dos ciclos BIG-CC em seu conjunto, através da comparação de

[18] Por exemplo, associadas à sua utilização sazonal e ao próprio desenvolvimento de mercado.

resultados da modelagem computacional para quatro estratégias de operação das turbinas com gases de baixo poder calorífico.

O capítulo 4 corresponde a artigo submetido à revista Energy – The International Journal. O texto descreve a modelagem computacional adotada para se analisar os efeitos da queima conjunta de gás natural e gases provenientes da gaseificação de pontas e folhas. Os resultados da modelagem permitem a determinação da composição ótima da mistura combustível do ponto de vista do desempenho das turbinas a gás e do ciclo combinado em seu conjunto. Os resultados da opção cofiring são então comparados com alguns resultados reportados no capítulo 3, identificando-se vantagens e desvantagens da opção cofiring.

O capítulo 5 corresponde a um segundo artigo submetido à revista Energy – The International Journal. O texto trata da análise econômica da opção cofiring e está intimamente associado aos resultados do capítulo 4. Um modelo que permite a identificação e a análise de fatores de escala foi aplicado ao estudo. Aspectos associados à logística de transporte da biomassa também foram considerados.

Finalmente, no capítulo 6 faz-se a discussão geral dos resultados e a análise crítica da alternativa objeto de estudo. Recomendações de futuros estudos são apresentadas ao final.

Capítulo 2

Aspectos Relevantes do Cenário Energético Brasileiro

2.1 Introdução

Neste capítulo são avaliados aspectos relevantes do contexto energético Brasileiro e Paulista, em relação ao escopo deste trabalho. A opção cofiring aqui analisada é ampla e a sua implementação envolveria os setores elétrico, sucro-alcooleiro e de gás natural. Como a proposta da tese é analisar como o cofiring de gás natural e biomassa poderia melhorar a performance técnica e econômica de sistemas térmicos baseados na gaseificação da biomassa, não há a pretensão de aprofundar-se na análise do setor energético Brasileiro. Em princípio, o contexto é favorável à opção cofiring no momento atual. Os pontos favoráveis decorrem da necessidade de expansão da capacidade de geração elétrica, dos riscos associados aos investimentos em novas termelétricas a gás natural, da potencial evolução do mercado de gás natural e, também, da disponibilidade de biomassa no setor sucro-alcooleiro de São Paulo, que deve ser crescente.

A geração elétrica em sistemas cofiring pode reduzir os riscos do investidor privado em relação à alternativa convencional de geração em ciclos combinados que utilizam apenas o gás natural. Estes riscos estão associados aos preços do gás, fixados em dólares americanos, à rigidez dos contratos "take or pay" e à dependência de um único fornecedor. A própria evolução futura do mercado de gás natural pode representar uma justificativa para a opção cofiring na geração de eletricidade.

A opção cofiring tal como analisada neste trabalho, isto é, em termelétricas, teria menos sentido na hipótese de disseminação da cogeração nas próprias usinas, com produção de energia elétrica excedente e ampla utilização da biomassa disponível. Nesse caso, no entanto, a opção cofiring poderia ser explorada nas próprias usinas. Essa alternativa não é analisada nesta tese.

A opção analisada pressupõe a geração de energia firme, da forma mais eficiente possível e com o benefício de economias de escala. Os empreendimentos seriam construídos próximos à região canavieira e próximos ao gasoduto Brasil-Bolívia, ou de outros que venham a existir no futuro. Acredita-se que o setor sucro-alcooleiro seria um grande beneficiário, em função da diversificação da atividade econômica.

2.2 O setor elétrico Brasileiro

2.2.1 As reformas e o momento atual

Desde a década de 1950 o setor elétrico brasileiro esteve organizado como um monopólio, com forte participação do Estado no planejamento, na operação e na realização dos investimentos (Mendonça e Dahl, 1999). No final da década de 1970 o setor elétrico começou a perder capacidade de investimento devido aos débitos internacionais. A partir dos anos 1980, o Governo Federal passou a controlar as tarifas, na tentativa de conter a alta inflacionária. A combinação de baixas tarifas e a perda de acesso ao crédito internacional acarretaram drástica redução dos investimentos no setor elétrico, que caíram cerca de 2,5 vezes entre 1977 e 1988 (Oliveira e Araújo, 1996).

As reformas do setor elétrico Brasileiro tiveram início em 1995, seguindo tendências políticas de privatização e desregulamentação, o que também foi verificado em vários outros países. As reformas visaram reduzir o papel do Estado à regulamentação e à elaboração de políticas, transferindo a responsabilidade de investir ao setor privado. As reformas também visaram o aumento da concorrência na geração e na comercialização de energia, para o que foi definido um novo arcabouço legal, a possibilidade de comercialização de energia no atacado e o livre acesso às redes de transmissão e distribuição (Mendonça e Dahl, 1999).

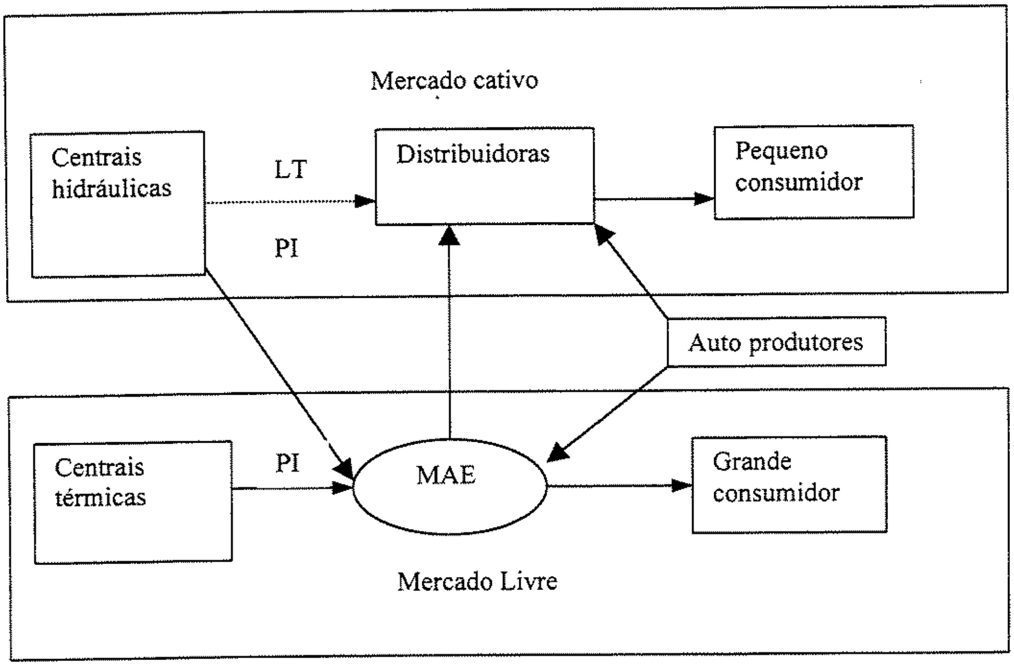

Figura 2.1. Esquema simplificado do novo modelo do setor elétrico

Uma esquematização simplificada do novo modelo do setor é apresentada na Figura 2.1. As distribuidoras e os grandes consumidores podem comprar energia dos produtores independentes ou de auto produtores através do MAE (Mercado Atacadista de Energia) ou através de contratos bilaterais. A transmissão da energia é assegurada por ativos (linhas de transmissão – LT) que continuam sob controle estatal. O termo produtor independente (PI) corresponde ao agente privado que atua na geração de eletricidade. Os produtores independentes e o MAE são os agentes que caracterizam o mercado livre. Os pequenos consumidores fazem parte do mercado cativo, sendo compulsoriamente atendidos pelas distribuidoras concessionárias. Os contratos antigos entre geradoras e distribuidoras também caracterizam o mercado cativo. A partir de 2002 esses contratos começarão a ser reduzidos a uma taxa de 25% ao ano (Mendonça e Dahl, 1999).

A privatização das distribuidoras é o ponto que mais avançou na implementação do novo modelo. Desde a primeira privatização, realizada em 1995, até 2000, foram vendidas 24 concessionárias de energia elétrica, correspondendo a 65% do mercado de distribuição (Jornal do Brasil, 2001a). Por outro lado, a privatização na geração está restrita a apenas uma empresa federal, a Gerasul, que foi privatizada em 1998. Outras grandes geradoras federais – Furnas Centrais Elétricas, CHESF e Eletronorte – tinham sua privatização programada para 1999 (Mendonça e Dahl,1999), mas há grande resistência política (Jornal do Brasil, 2001a). Ainda permanecem sob controle estatal 78% da geração elétrica.

Mendonça e Dahl (1999) entendem que as baixas tarifas, definidas nos contratos em vigor entre empresas geradoras e distribuidoras, são um impasse para a privatização das geradoras. Por outro lado, a expectativa de expansão da capacidade de geração ainda não se concretizou. A expansão até agora se limitou quase que exclusivamente à finalização de obras que tinham sido iniciadas antes da reforma. O interesse do capital privado em investir em novas hidrelétricas tem sido pequeno. Por exemplo, a ANEEL tinha o objetivo de autorizar a concessão de 19 novas instalações em 1998, totalizando uma capacidade de 3600 MW, mas só conseguiu viabilizar 1635 MW (Mendonça e Dahl, 1999). Havia grande expectativa com respeito à construção de termelétricas a gás natural, mas o interesse do investidor foi em muito reduzido após a desvalorização do Real, desde 1998.

A falta de investimentos nos últimos anos na construção de novas usinas e linhas de transmissão, a indefinição no preço do gás natural e o mais baixo nível de chuvas em 40 anos resultaram na atual crise energética brasileira. A escassez de energia submete o país a um regime de racionamento de energia elétrica desde junho de 2001. Este racionamento afetará o crescimento da economia, deve resultar na elevação das tarifas elétricas e alterar a vida de empresas e pessoas (Jornal do Brasil, 2001b).

Entre as alternativas que podem garantir substancial expansão da oferta, as termelétricas a gás natural são as instalações que podem ser viabilizadas no menor prazo possível, reduzindo os riscos de um desabastecimento mais prolongado (Jornal do Brasil, 2001c). Além disso, defende-se que as termelétricas são necessárias para garantir o mercado inicial para o gás Boliviano. O interesse do investidor privado nas termelétricas a gás natural está associado ao seu custo de capital relativamente baixo, ao menor período de construção, à alta eficiência térmica e à habilidade de operar na maior parte do tempo. Além disso, existem sinergias entre os interesses dos setores elétrico e de gás natural, e grande parte dos investidores potencial em termelétricas é empresas comercializadoras de gás.

No curto prazo a dificuldade de viabilização de investimentos em termeletricidade está relacionada principalmente aos riscos cambiais, e ao possível desajuste entre as receitas em Reais e os custos dos equipamentos e do gás, em Dólares. As obrigações contratuais impostas pela Gaspetro[1] também representam uma barreira: o prazo dos contratos é de 20 anos e esses são feitos sob um regime "take or pay", segundo o qual o combustível deve ser pago independentemente de estar sendo usado. Este tipo de contrato é inconveniente em um sistema predominantemente hidrelétrico, consideradas as flutuações de disponibilidade de energia. Esta questão será discutida adiante.

2.2.2 Caracterização do setor elétrico em São Paulo

São Paulo é o Estado mais rico e mais densamente povoado do Brasil. Devido a seu parque industrial, o Estado tem o maior consumo de energia do país, representando cerca de 35% do consumo total. Ainda que uma quantia expressiva da eletricidade seja gerada no Estado, o que corresponde a um valor em torno de 25% da eletricidade gerada no país, uma parcela significativa precisa ser importada de outros Estados. Como pode ser observado na Tabela 2.1 o percentual de geração hidrelétrica no Estado de São Paulo é ainda mais significativo do que no Brasil.

A Tabela 2.2 apresenta a composição do parque gerador no Estado São Paulo em 1997. Menos de 10% da capacidade instalada corresponde a sistemas de cogeração, sendo que a maior fração está no setor sucro-alcooleiro. Tal como comentado anteriormente, a capacidade instalada nesse setor garante basicamente a auto suficiência, sendo uma pequena fração exportada. No final dos anos 1990 a capacidade associada à exportação correspondia a apenas 25 MW (Coelho, 1999). A comercialização de excedentes tem aumentado, ainda que lentamente, e em 2001 os contratos de comercialização correspondem à cerca de 85 MW.

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[1] Subsidiária da Petrobrás para a venda do gás.

Uma parcela significativa do consumo industrial de energia é atendida pela biomassa e, principalmente, pelo bagaço de cana, em função da importância do segmento no Estado e, também, da baixa eficiência dos sistemas de cogeração existentes. Em relação ao consumo total de combustíveis no Estado o bagaço representa algo em torno de 14%.

Tabela 2.1 Alguns indicadores do setor elétrico em1999

	Brasil	São Paulo
Capacidade instalada (GW)	68,2	nd
Geração de eletricidade (TWh)	333,2	70[1]
Consumo de eletricidade (TWh)	314,7	99,2
Geração hidrelétrica (%)	88	95[1]

Nota: [1] em 1997
nd = não disponível
Fontes: [1] BEESP (1999)
MME (2000)

Tabela 2.2 Capacidade instalada de geração elétrica no Estado de São Paulo (1997)

	Capacidade instalada (MW)
Hidrelétricas	10.514
Termelétricas a óleo	500
Cogeração	.
Setor sucro-alcooleiro	650
Química/petroquímica	141
Papel/celulose	93
Alimentos e bebidas	65
Siderurgia	27
Total em cogeração	976
Total	11.990

Fonte: Ramalho, 1999

2.2.3 Crescimento da demanda

Antes da reestruturação do setor elétrico, o incremento na capacidade necessário para acompanhar o crescimento da demanda era determinado por planos governamentais, denominados planos decenais. Após as reformas, como não cabe mais ao Estado garantir a oferta, os planos de expansão passaram a ser meramente indicativos. O papel dos planos é, na verdade, a indicação dos investimentos que devem ser feitos para garantir o suprimento. A execução das obras relacionadas, e a conseqüente implementação do plano, dependem dos investidores.

Na Figura 2.2 apresenta-se a evolução do consumo de eletricidade no Brasil e no Estado de São Paulo no período 1984-1999. Durante esse período o consumo cresceu a uma taxa média de 3,5% ao ano em São Paulo e 4,6% ao ano no Brasil. Nos últimos anos o consumo cresceu mais intensamente entre 1993 e 1997, devido aos efeitos da estabilização econômica, tendo caído desde então.

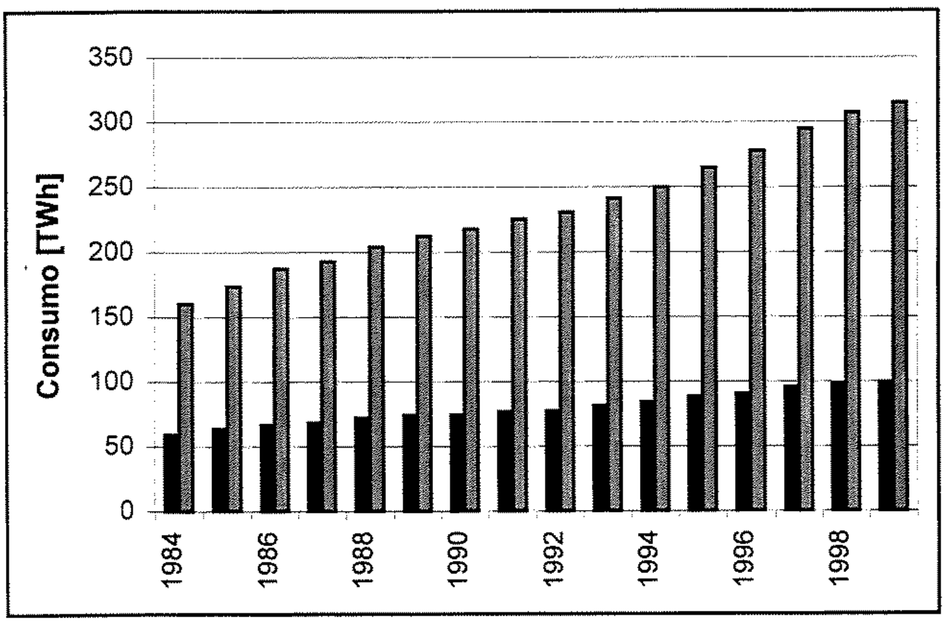

Figura 2.2 Evolução do consumo de eletricidade no Estado de São Paulo e no Brasil (hachurado) – 1984-1999 (MME, 2000)

A revisão do planejamento da expansão feita em 1998 previa um crescimento do consumo equivalente a 4,5% ao ano (Tautz, 1998), sendo que as taxas verificadas em 1998 e 1999, respectivamente, foram 4,2 e 2,5% no Brasil e 2,3 e 1,2% em São Paulo (MME, 2000). Com a expectativa de gradual retomada do crescimento econômico, a previsão da ELETROBRÁS para o crescimento do consumo até 2004, no Brasil, é de 5,5% ao ano (Jornal do Brasil, 2001a). O objetivo estabelecido pelo plano de expansão revisado é o crescimento da capacidade instalada para 95,7 GW em 2007. Para que essas metas fossem atendidas até 2004 haveria a necessidade de que a capacidade instalada crescesse no mínimo 4,6 GW por ano, o que segundo os cálculos da ELETROBRÁS requer investimentos da ordem de R$ 10 bilhões anuais (Tautz, 1998).

Tendo em vista a necessidade de ampliar significativamente a capacidade instalada foi lançado em fevereiro de 2000 o Programa Prioritário de Termelétricas (PPT) com o propósito de viabilizar até o início de 2004 49 novas instalações termelétricas. Até fins de abril de 2001, apenas 13 dessas usinas tinham alguma garantia contratual (Jornal do Brasil, 2001c), sendo que nem mesmo o Governo sabe avaliar quais e quantos empreendimentos podem ser viabilizados a tempo. Em dado instante em 2000 79 centrais foram cogitadas, sendo que 85% da capacidade prevista (19 GW) correspondia a centrais a gás natural e 31 centrais (12 GW) eram previstas para serem construídas nos Estados de São Paulo e Rio de Janeiro. Oficialmente, as 49 termelétricas do PPT somariam 17 GW de capacidade adicional, sendo 15 GW em térmicas a gás natural. As termelétricas a gás também são consideradas essenciais para garantir no curto-médio prazos o consumo do gás importado da Bolívia, mas a operação a plena carga dos 15 GW previstos consumiria 60 milhões m^3/dia.

2.3. Condicionantes às termelétricas a gás natural

Ainda que as termelétricas sejam essenciais para garantir um consumo mínimo de gás durante os primeiros anos de operação do gasoduto Brasil-Bolívia, há restrições associadas à inserção de tal capacidade de plantas térmicas em um sistema predominantemente hidrelétrico. A grande barreira é a variabilidade na afluência dos reservatórios das hidrelétricas, que apresentam comportamento estocástico e com uma ampla faixa de capacidades de produção ao longo do tempo (Ramos e Ennes, 1996). Os reservatórios e a motorização das hidrelétricas são dimensionados para condições extremas de hidrologia (secas), sendo possível o aproveitamento de capacidade adicional no caso de hidrologia favorável. Essa capacidade de produção adicional é denominada energia secundária. O aproveitamento dessa energia adicional, de baixo custo, que acabaria sendo vertida se não houvesse geração, faz com que seja lógico o desligamento das centrais térmicas nos momentos de hidrologia favorável. A operação das termelétricas apenas no momento de hidrologia desfavorável, permitindo "firmar" a energia secundária, é chamada "complementação térmica".

A operação em complementação térmica pode ser melhor compreendida com o auxílio da Figura 2.3. O fluxo de energia hídrica corresponde à potência que poderia ser obtida do fluxo d'água afluente às hidrelétricas. Nos períodos chuvosos, o fluxo é muito maior que a capacidade firme, assegurada pela capacidade de armazenamento e motorização. Parte do fluxo de energia hídrica que supera a capacidade firme deve ser armazenado para cobrir o suprimento durante a estação seca ou para anos subseqüentes. A parcela restante pode ser utilizada, se houver capacidade de turbinamento, mas é, na maior parte do tempo, perdida. A complementação do sistema hidrelétrico com plantas térmicas permite "firmar" parte da energia secundária que de outra forma seria vertida. A figura ilustra o caso de aumento de 1 GW da capacidade hidrotérmica firme.

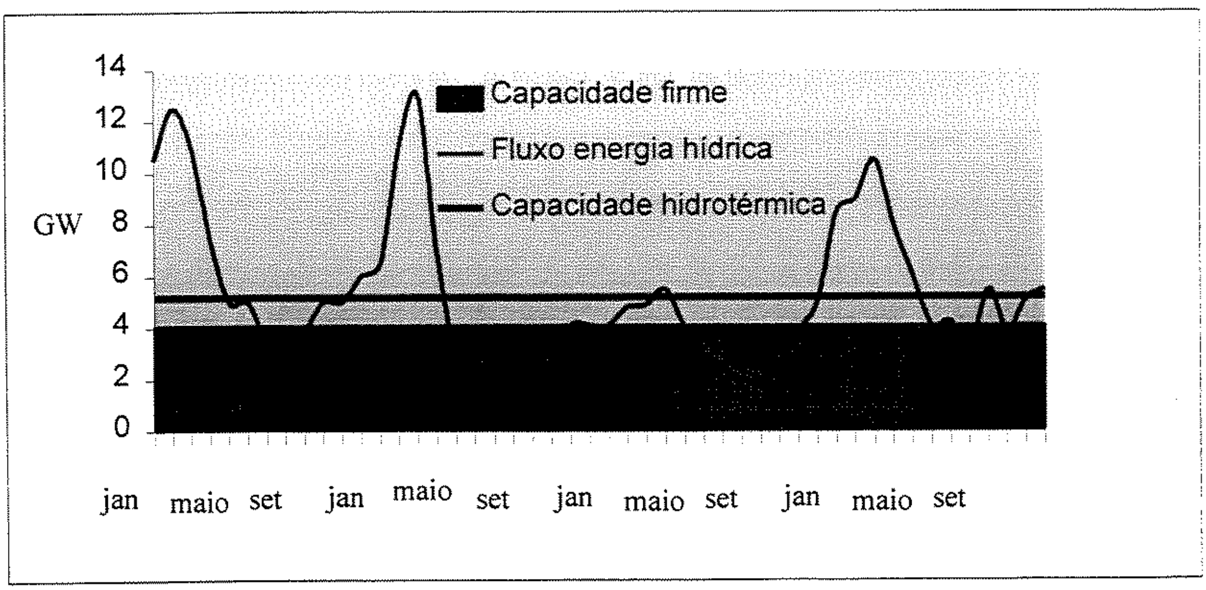

Figura 2.3. Esquema do aproveitamento do fluxo de energia hídrica em um sistema com complementação térmica

O regime de complementação térmica conflita com a rigidez dos contratos de suprimento de gás natural "take or pay". O desligamento ou a operação em carga parcial de termelétricas a gás natural levaria a custos de operação muito altos, já que o combustível teria que ser pago mesmo sem utilização. Ramos e Ennes (1996) discutem soluções para minimizar os encargos econômicos do contrato "take or pay" para os investidores em ciclo combinado. Dois modelos conceituais de otimização da operação das térmicas a gás são apresentados. São eles:

1. Uma planta híbrida, com uma parcela a gás natural e outra a óleo combustível, que operaria com um consumo mínimo equivalente a 50% do volume de gás contratado. O gás excedente seria vendido a "consumidores pulmão" por um preço equivalente ao do gás na "boca do poço". Nos períodos hidrologicamente desfavoráveis o gás seria direcionado para a termelétrica.

2. O armazenamento de gás natural de modo a regularizar o suprimento, que seria utilizado em períodos hidrológicos desfavoráveis, para compensar o crescimento do mercado maior que previsto ou, ainda, compensar atrasos irrecuperáveis na expansão da oferta.

As duas alternativas são apenas propostas que necessitam um estudo mais aprofundado. Uma restrição é o fato de que a exploração, o transporte e a comercialização do gás natural são feitos por agentes não necessariamente interessados na racionalização da operação do sistema hidrelétrico. No caso da primeira proposta, um problema adicional é o baixo preço de venda do gás excedente.

Na prática existem outras restrições às termelétricas a gás natural no Brasil. Além das restrições relativas ao prazo dos contratos, já comentadas, existem riscos cambiais associados à compra do gás em dólares, enquanto os reajustes tarifários para a eletricidade produzida devem ser anuais. A solução ora encaminhada obriga a PETROBRÁS a suportar durante até 12 meses eventuais prejuízos decorrentes da variação cambial. Por fim, e não menos importante, existem restrições ambientais à construção de termelétricas nos centros de carga, relativas às emissões de óxidos de nitrogênio e ao consumo de água nos sistemas de resfriamento. Vários projetos têm enfrentado resistência popular e outros foram cancelados. Uma das maiores usinas previstas, por exemplo, teve sua construção em Cubatão embargada por uma liminar em resposta a uma ação civil pública que se fundamenta no problema das emissões atmosféricas (Jornal do Brasil, 2001c).

2.4. O gás natural no Brasil

O gás natural foi por algum tempo considerado uma fonte de menor importância para a definição da matriz energética brasileira. Ainda que o gás natural estivesse disponível, principalmente associado ao óleo, era ora reinjetado nos reservatórios de forma a aumentar a pressão, ora queimado localmente nas plataformas (Davison et al.,1988). O interesse em relação ao gás natural começou a aumentar e uma revisão da matriz energética, feita pelo Governo Federal, em 1990, conduziu a recomendações para aumentar a parcela de gás natural no consumo de energia primária no Brasil, que deveria chegar a 12% até 2010[2] (Turdera, 1997). Em função das baixas reservas no país, para que essa meta fosse atingida era necessário importar gás natural e, assim, uma idéia que já vinha dos anos 80 (Davison et al., 1988), de se importar gás da Bolívia, foi revitalizada. O gasoduto Brasil-Bolívia já entrou em operação, mas o mercado e a infra-estrutura de distribuição ainda estão em desenvolvimento. Consumidores de grande porte, como as termelétricas, são fundamentais para se garantir o consumo em larga escala, o que é essencial para a remuneração do investimento enquanto o mercado é formado. O texto a seguir trata do gasoduto em si, do suprimento e do desenvolvimento do mercado de gás natural.

2.4.1 O gasoduto Brasil- Bolívia

Enquanto a Bolívia conta com reservas provadas razoavelmente expressivas – que em 2001 são estimadas em 681 bilhões de metros cúbicos[3] – e um consumo interno de apenas 2 milhões $m^{3/}$dia, o Brasil pretende aumentar a participação do gás natural na matriz sem ter uma produção

[2] Em 2000 o gás natural contribuiu com apenas 4% na matriz.

[3] As reservas prováveis de gás natural da Bolívia somam 654 bilhões de metros cúbicos e as possíveis são estimadas em 622 654 bilhões de metros cúbicos (Menezes, 2001).

suficientemente alta para isso (Turdera , 1997). O interesse mútuo levou a um acordo para a construção de um gasoduto entre os dois países. O contrato de suprimento inicial foi firmado para comercialização entre 8 e 9 milhões m^3/dia. O primeiro trecho do gasoduto atravessa Mato Grosso do Sul e São Paulo; uma derivação permite o transporte ao Rio Grande Sul e outra para Minas Gerais. A capacidade total do gasoduto já construído é de 30 milhões m^3/dia (Turdera, 1997). Era previsto que um volume adicional de 12 milhões de m^3/dia deveria ser contratado até 2003 (COMGÁS, 2001), mas negociações recentes podem fazer que com a expansão a capacidade suprida chegue a 60 milhões de m^3/dia.

2.4.2 O mercado de gás natural em São Paulo

No Estado de São Paulo, antes da construção do gasoduto Brasil-Bolívia, o mercado de gás natural se restringia à região do Vale do Paraíba, com suprimento provindo da bacia de Campos, no Rio de Janeiro. Este suprimento teve início em 1987, através de contrato assinado com a PETROBRÁS para um suprimento de 3 milhões de m^3/dia (COMGÁS, 2001). Um detalhamento do mercado de gás natural àquela época é apresentado na Tabela 2.3.

Tabela 2.3 Mercado de gás natural antes do gasoduto Brasil-Bolívia

Tipo de Indústria	Parcela do mercado (%)
Petroquímica	28
Metalurgia	26
Vidro	11
Papel e celulose	10
Alimentos e bebidas	6
Outras	19

Fonte: Gazeta Mercantil (1999)

O volume inicial do gás Boliviano contratado para o Estado de São Paulo é de 4 milhões m^3/dia. A previsão inicial é de que o volume comercializado deveria atingir 8,1 milhões m^3/dia no oitavo ano do contrato, dentro de um acordo de fornecimento de 20 anos (COMGÁS, 2001). Não é possível prever como o mercado de gás natural vai se desenvolver, mas existem indicações de que há um grande mercado potencial em vários setores da economia. Em 1998, a Secretaria de

Energia de São Paulo previa uma demanda dos mercados residencial e industrial em torno de 15 milhões de m^3/dia e uma demanda para termeletricidade da mesma ordem (Brasil Energia, 1997).

A Tabela 2.4 apresenta projeções de mercado para o Estado de São Paulo, elaboradas a partir de estudos feitos pela PETROBRÁS em 1992. De acordo com esses dados, o mercado potencial em São Paulo seria maior que a soma da capacidade do gasoduto Bolívia-Brasil e da oferta potencial da Bacia de Santos. O resultado apresentado para o ano 2000 deve ser confrontado com o consumo atual em todo o país, que é estimado em 18,5 milhões m^3/dia. Já a Tabela 2.5 indica os potenciais mercados para o gás natural no Brasil, em 2010. É interessante notar que o mercado potencial para gás natural automotivo é maior que os mercados residencial e comercial juntos.

Tabela 2.4 Mercado potencial para gás natural no Estado de São Paulo (milhões m^3/dia)

	1995	2000	2010
Mercado potencial	8,29	18,22	34,57

Fonte . PETROBRAS (adaptado de Rodrigues, 1995)

Tabela 2.5 Mercado potencial para gás natural no Brasil, em 2010 (milhões m^3/dia)

Uso	Mercado potencial
Automotivo	6,37
Residencial	2,43
Comercial	2,24
Geração elétrica + cogeração	22,79
Industrial – matéria prima	6,72
Industrial energético	76,37
Total	116,92

Fonte . PETROBRAS (adaptado de Rodrigues, 1995)

2.4.3 A evolução do mercado

Um gasoduto representa um grande investimento inicial. O gasoduto Brasil-Bolívia – Gasbol, por exemplo, custou US$ 1,8 bilhões. Para remunerar tal investimento, ou desenvolve-se rapidamente um mercado no qual os pequenos-médios consumidores estão dispostos a pagar mais pela qualidade do combustível (consumidores "*premium*"), ou garante-se um mercado que consuma uma quantidade muito grande de forma a compensar o menor preço pago. No caso da opção pelo consumo em larga escala, o setor elétrico é o candidato alvo (Davison et al., 1988).

Com o desenvolvimento do mercado e com a implementação da infra-estrutura necessária, as oportunidades junto aos consumidores menores (setor residencial e comercial) aparecerão. Em um mercado já desenvolvido estes consumidores pagam um preço mais alto pelo gás e são responsáveis pelos maiores lucros na comercialização (Davison et al., 1988). A realização do mercado de gás natural possui uma baixa velocidade inicial, resultando em um crescimento de demanda incompatível com as necessidades de receita impostas pela remuneração de investimentos em infra-estrutura (Ramos e Ennes, 1996). A participação do setor elétrico, com centrais termelétricas de médio-grande porte, cria uma demanda firme nos anos iniciais do empreendimento nos quais o mercado de gás natural, especialmente no nível da distribuição (baixo consumo individual), ainda não se encontra consolidado.

2.4.4 Usos do gás natural

Um esquema simplificado dos usos potenciais do gás natural é apresentado na Figura 2.4. O chamado gás natural úmido é aquele obtido quando de sua exploração, podendo ser utilizado na própria lavra para a produção de gasolina natural (pentano e hexano) e de gás liqüefeito de petróleo. O gás natural seco é o gás beneficiado e transportado para ser utilizado como combustível ou matéria prima. O gás natural é matéria prima para a produção de amônia, metanol, hidrogênio, gasolina e diesel sintético (Rodrigues, 1995). Como combustível, pode ser utilizado em fornos industriais, caldeiras, turbinas e motores, fogões e aquecedores.

2.4.4.1 Uso industrial

Em geral o mercado para gás natural na indústria é dividido em duas categorias, a dos consumidores de larga escala e a os consumidores "*premium*". Os consumidores de larga escala consomem grandes quantidades para simples geração de calor. O consumidores "*premium*" utilizam o gás natural em processos nos quais a qualidade da combustão é o aspecto mais importante (Davison et al., 1988). Nesses casos o gás possui um valor mais alto. Consumidores de grande porte para os quais o gás natural concorre com outros combustíveis incluem, por exemplo, a indústria de cimento. As indústrias nas quais o gás tem um valor "*premium*" incluem as cerâmicas e as indústrias de vidro. Nesses casos, o alto conteúdo de enxofre e a quantidade de particulados nos gases tornam o uso dos óleos combustíveis, por exemplo, inadequado.

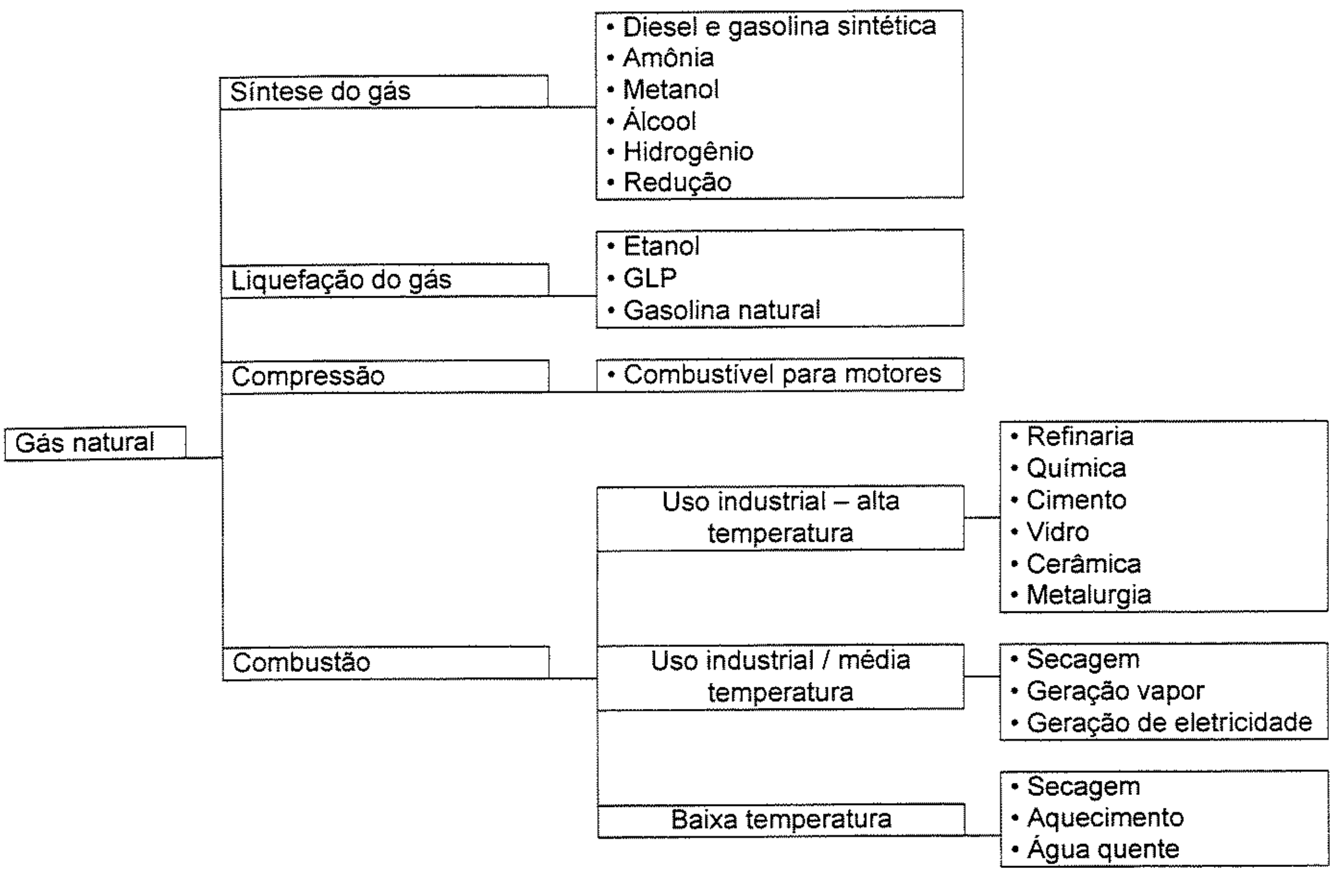

Figura 2.4 Usos potenciais do gás natural

Grande parte das indústrias cerâmica e de vidro no Brasil utiliza GLP como combustível, que é subsidiado e é em grande parte importado. A indústria cerâmica é, inclusive, uma das mais interessadas na expansão da oferta de gás natural, já que a substituição do GLP pode reduzir os gastos em combustível em até 30% (Gazeta Mercantil, 1998). Já a indústria petroquímica utiliza gás natural como matéria-prima para produzir amônia ou metanol, o que representa um outro caso de uso "*premium*" (Davison et al., 1988).

Mesmo nas indústrias que não têm demanda significativa de calor e não têm restrições quanto à qualidade da combustão, o uso do gás natural sempre traz vantagens por não requerer armazenagem, prover facilidades no fornecimento, além de, em geral, minimizar as emissões atmosféricas.

2.4.4.2 Setores residencial e comercial

O setor residencial e, particularmente, o setor comercial são freqüentemente chamados como mercados "*premium*" por excelência (Davison et al., 1988). Para que uma rede de distribuição de gás seja lucrativa, deve servir uma área com um número suficiente de hotéis, prédios comerciais, além de um grande número de residências de alta renda. O Gasbol vai suprir áreas com elevada concentração urbana e com as mais elevadas rendas per capita no Brasil, logo os investimentos necessários em distribuição e substituição de equipamentos (principalmente chuveiros elétricos) não deve sofrer restrições financeiras. As concessionárias de gás natural deveriam ser, em princípio, as mais interessadas em viabilizar esse mercado pois o setor residencial proporciona a maior parcela de receita (Brasil Energia, 1997b).

2.4.4.3 Gás natural comprimido

O gás natural comprimido – GNC é utilizado em motores de combustão interna. No Brasil, esse mercado deveria ser considerado uma prioridade por razões estratégicas relacionadas à importação de óleo diesel, bem como por causa da poluição atmosférica nas grandes cidades. O gás natural prolonga a vida do motor por não produzir resíduos pós queima, além de ser menos poluente e, em geral, mais barato que os combustíveis que substitui (Davison et al.,1988). O uso de gás natural para veículos é ainda incipiente, porém o número de veículos rodando com gás natural está crescendo rapidamente e existem boas perspectivas para este mercado. Por outro lado, o número de veículos rodando com gás natural no Brasil é ínfimo se comparado com o número de veículos a gás natural na Argentina, por exemplo. Aquele país possui a maior frota de veículos a gás no mundo, em torno de 400.000 veículos (Sharf, 1998).

Na cidade de São Paulo uma lei municipal foi decretada em 1991 determinando que todos os ônibus da cidade deveriam ser convertidos para gás natural até 2007 (COMGÁS, 2001). Só em São Paulo existem em torno de 10 mil ônibus, o que representaria, a grosso modo, um consumo de 1 milhão m^3/dia (Sharf, 1998). O potencial ainda é limitado pelo sistema de distribuição.

2.5. O setor sucro-alcooleiro e a disponibilidade de biomassa

2.5.1 Informações gerais sobre o setor

O Brasil é o maior produtor mundial de cana de açúcar, em função da produção combinada de açúcar e álcool para fins automotivos. Esta produção atingiu 300 milhões de toneladas de cana na safra 1997-98 e caiu para cerca de 250 milhões na safra 2000-01. Na safra 1997-98 em torno de 180 milhões de toneladas foram produzidas no Estado de São Paulo (COPERSUCAR, 1999). Naquela safra, em São Paulo, a cana foi processada em 135 unidades de produção que incluem destilarias autônomas e usinas de açúcar e álcool. Embora varie a cada safra, pode-se dizer que a grosso modo metade da cana produzida é utilizada para a produção de açúcar.

O Brasil é o maior produtor e o maior exportador de açúcar de cana (Silva et al., 1999). A quase totalidade do álcool produzida é usada para fins automotivos, suprindo a demanda de etanol anidro, para mistura com a gasolina (até 25% em volume), e de etanol hidratado, que é utilizado puro nos motores a álcool (aproximadamente 35% da frota). Existe ainda um potencial não explorado, para mistura com o óleo diesel (até 15% em volume) e também para a exportação, em particular para o MERCOSUL (Braunbeck et al., 1999).

A indústria do açúcar e do álcool enfrenta um período de transição depois de 64 anos de tutela governamental. A desregulamentação do setor começou com o desmonte do Instituto do Açúcar e do Álcool (IAA) e a gradativa redução do suporte governamental às usinas e destilarias. Em 1997 o Governo Federal deixou de fixar o preço para o açúcar e para o álcool anidro e, em 1999, os preços da cana-de-açúcar e do álcool hidratado foram liberados (Silva et al., 1999).

Em um cenário que busca ser mais competitivo e à luz das flutuações dos preços de açúcar e do aumento da concorrência internacional (Silva et al., 1999), as indústrias de cana procuram aumentar a eficiência e a produtividade. Ainda que o açúcar brasileiro seja competitivo com outros países em termos de produto, preço e distribuição, o setor ainda pode se beneficiar de ganhos significativos com mudanças na logística, melhorias no processo e com a cogeração. Os custos de produção do álcool também podem ser reduzidos, embora seja difícil determinar custos médios de produção[4].

No Estado de São Paulo os avanços tecnológicos industriais mais importantes se deram na extração do caldo, na reciclagem da vinhaça e na redução do tempo de fermentação. Na área agrícola a introdução da ferti-irrigação foi um importante avanço tecnológico, mas avanços substanciais foram obtidos com o melhoramento genético de novas espécies. Ferti-irrigação é um termo freqüentemente usado no Brasil para descrever o processo de aplicação de vinhaça como fertilizante (Braunbeck et al., 1999).

A intensificação da mecanização, desde a preparação do solo até a colheita, faz parte dos esforços de redução dos custos. A estimativa de redução de custos da cana associada com o plantio mecanizado é da ordem de 25% (Silva et al., 1999). A colheita continua a ser a etapa menos avançada na produção de cana, já que a maioria das plantações ainda é queimada sistematicamente para permitir a colheita manual. Outra tendência para redução de custos no setor é a terceirização da logística.

A utilização de resíduos de cana como combustível para geração de energia elétrica, tema de estudo deste trabalho, pode representar uma oportunidade de obtenção de receita adicional pelas indústrias, seja como produtor de eletricidade ou ainda pela comercialização dos resíduos. A produção de eletricidade ainda não é fonte de receita substancial para as usinas do Estado. Outras oportunidades para a diversificação estão no uso do bagaço como matéria prima industrial e, inclusive, para a produção de álcool a partir do processo de hidrólise ácida (Walter, 1994). A

[4] Estimativas disponíveis na literatura apresentam variação considerável.

hidrólise do bagaço pode ter um grande potencial ainda que a tecnologia correspondente não esteja disponível comercialmente (Moreira, 2000).

2.5.2 A disponibilidade de pontas e folhas

A prática de colheita da cana queimada é ainda largamente utilizada no Brasil, pois representa um processo mais eficiente tanto para o corte de cana manual como o mecanizado. A colheita de cana crua é mais penosa e apresenta riscos para os trabalhadores que, consequentemente, cobram mais. Por outro lado, as colheitadeiras existentes são em torno de 30 a 40% menos eficientes no caso da colheita da cana crua. Dessa forma, no Estado de São Paulo, até pouco tempo a colheita de cana crua era praticada apenas no raio de 1km em torno das cidades, como imposto pela legislação (Braunbeck et al., 1999).

Essa situação deve mudar devido à legislação no Estado de São Paulo requerer a extinção da colheita de cana queimada até 2005, em regiões com topografia mais favorável, e até 2010 nas regiões de topografia menos adequada à colheita mecanizada. A mecanização deve ser o fator mais importante na redução dos custos de produção no setor. Enquanto os custos de colheita manual e carregamento da cana queimada excedem US$ 4,00/t, os custos para colheita mecanizada de cana queimada e crua ficam em torno de US$ 2,00 e US$ 3,00/t, respectivamente (Braunbeck et al., 1999). Na safra 97/98, em São Paulo, em torno de 18% do corte de cana foi realizado mecanicamente (IDEA, 1999). Algumas usinas apresentam alta percentagem de mecanização, como é o caso da Usina São Martinho, que já apresentava 89% da cana colhida mecanicamente na safra de 93/94. Entretanto, apenas 2% da cana colhida mecanicamente era crua (Braunbeck et al., 1999).

O principal benefício da legislação que decreta o fim das queimadas é o ambiental. As queimadas são responsáveis por emissões locais de monóxido de carbono e particulados, o que afeta a saúde humana, podendo provocar doenças respiratórias (Braunbeck et al., 1999). Além disso, as queimadas emitem metano, gás que contribui para com o efeito estufa (Macedo, 1998). O fim das queimadas também reduz perdas de sucrose, que podem chegar a 15% (Fernandes e Irvine, 1986), e traz benefícios agronômicos quando parte dos resíduos é deixada no solo. De acordo com experimentos realizados em projeto da COPERSUCAR (1999a), quantidades de palha superiores a 66% do total produzido controlam plantas daninhas de ciclo anual em níveis de eficiência superiores a 90%. Esse valor é compatível com a maioria dos tratamentos baseados em herbicidas empregados com sucesso na lavoura canavieira (COPERSUCAR, 1999a). Outros potenciais benefícios seriam a conservação da umidade do solo, a redução da erosão e a melhoria da quantidade de nutrientes no solo, especialmente o nitrogênio (COPERSUCAR, 1999b).

As limitações técnicas associadas à tecnologia existente implicam redução da velocidade de implementação da colheita de cana crua. É necessário o desenvolvimento das colheitadeiras para melhoria de sua performance, aumento da flexibilidade e redução dos custos do equipamento. A adaptação das máquinas à topografia do solo brasileiro, às características de produção e ao crescimento da cana é também requerida. Ainda assim, em torno de 50% da colheita deve ser completamente mecanizada até 2005, sendo em grande parte colheita de cana crua (Braunbeck et al., 1999).

A implementação da colheita da cana crua vai disponibilizar uma enorme quantidade de resíduos, que podem ser utilizados para geração de energia. A quantidade de resíduos da cana varia com a altura de corte dos ponteiros, com a variedade da cana, com a idade da cultura, entre outros fatores (COPERSUCAR, 1999c). Em geral, a quantidade de resíduos da cana de açúcar varia entre 10-18% da planta, em massa (base seca) (COPERSUCAR, 1998). A quantidade de resíduos disponíveis para utilização como combustível vai depender da quantidade de resíduos deixada no campo e da quantidade que pode ser coletada com mecanização. A recomendação da quantidade de resíduos deixada no campo varia entre 50 e 66% (COPERSUCAR 1999b; Braunbeck et al., 1999). A tecnologia corrente em colheitadeiras limita a colheita mecanizada a 45% da área plantada no Brasil. No Estado de São Paulo, onde a topografia é mais favorável, uma estimativa conservadora de 50% pode ser considerada. O desenvolvimento da tecnologia poderia fazer com que 90% das terras ocupadas por plantações tivessem colheita mecanizada. Com base nestas hipóteses é possível definir a disponibilidade mínima e máxima de resíduos. Os cenários de disponibilidade de resíduos são apresentados na Tabela 2.6, com base na safra de 97/98, em São Paulo (180 milhões de toneladas de cana) e para a média de pontas e folhas na planta por variedade de cana (15%) (COPERSUCAR, 1998).

Tabela 2.6 Disponibilidade de pontas e folhas em função da colheita mecanizada

Cenários	10^6 t (massa seca)	PCI (PJ, base seca)
Mínimo[1]	4,6	83
Máximo[2]	14,6	263

[1] 66% de palha no campo e 50% de plantações com colheita não mecanizada;
[2] 50% de palha no campo e 10% de plantações com colheita não mecanizada.

2.5.3 A utilização e a disponibilidade de bagaço

O bagaço é o resíduo obtido quando da moagem da cana nas unidades industriais. Nas usinas, o bagaço é o combustível das caldeiras que geram vapor. Esse vapor alimenta as turbinas que movem as moendas e geram eletricidade. O vapor de escape atende a demanda térmica do processo produtivo. Em São Paulo, em torno de 10% do bagaço disponível corresponde ao excedente, que é principalmente comercializado com indústrias do setor de alimentos.

Os sistemas de cogeração no setor sucro-alcooleiro são baseados em caldeiras de baixa pressão e turbinas de contra pressão. Embora ineficientes do ponto de vista termodinâmico, são capazes de suprir a demanda elétrica e, eventualmente, gerar alguma eletricidade excedente. A utilização ineficiente do bagaço decorre de um mercado, como combustível, bastante restrito. Historicamente, as condições pouco favoráveis e a baixa remuneração para venda de eletricidade excedente também desestimularam a melhoria de eficiência dos sistemas existentes. No final dos anos 1990 o valor para venda de excedentes através de contratos de longo prazo com as distribuidoras estava em torno de R$ 20/MWh. A situação era ainda pior para os contratos de curto prazo, nos quais a eletricidade era remunerada por apenas R$ 7,00/MWh, o que sequer era suficiente para cobrir os custos de conexão (Swisher, 1998). A situação mudou para melhor durante 2001, entre outros fatores por conta da crise elétrica.

Por outro lado, o potencial para produção de energia elétrica excedente no Brasil é bastante expressivo, como pode ser observado pelos números apresentados na Tabela 2.7.

Tabela 2.7 Potencial para produção de eletricidade excedente no Brasil

Tecnologia	Operação	Consumo de vapor no processo (kgv/tc)	Excedente elétrico (kWh/tc)	Potencial (MW)
Atual: ciclos a vapor de contra pressão, geração a 22 bar, escape a 2,5 bar	Na safra	500	0-10	800
Ciclos a vapor de contra pressão, geração a 80 bar, escape a 2,5 bar	Na safra	500	20-30	2.400
Ciclos a vapor de extração–condensação, geração a 80 bar, extração a 2,5 bar	Ano todo (1)	330 (3)	80-100	4.000
BIG-CC	Ano todo (1,2)	<330 (3)	200-300	12.000

Fonte: adaptado de COPERSUCAR (1998)

(1) Necessidade de recuperar a palha
(2) Tecnologia em desenvolvimento
(3) Tecnologia disponível mas não utilizada

Para que haja bagaço excedente nas usinas, que seria comercializado para produção de energia elétrica em termelétricas – tal como proposto neste trabalho – seriam necessários investimentos na etapa industrial visando a redução da demanda de vapor, além de melhorias na eficiência dos sistema de cogeração. A produção e venda de energia excedente nas usinas também afetaria a existência de excedentes. Uma avaliação do excedente de bagaço para tal finalidade foi feita em Souza et al. (2000) (ver Anexo 2). As hipóteses empregadas naquele estudo e os principais resultados finais de dois cenários são apresentados na Tabela 2.8.

Os dois cenários são válidos dentro de um horizonte de dez anos. Considerado o nível das tecnologias disponíveis comercialmente os cenários imaginados são conservadores, não sendo considerada a produção de eletricidade excedente, além de ser pequena a redução da demanda de vapor de processo. Além disso, imagina-se que os sistemas de cogeração operariam somente na safra, com vapor gerado a pressão relativamente baixa. Nos cenários I e II foi considerada a possibilidade de substituição de 50% dos equipamentos de cogeração em função da idade relativamente avançada do parque gerador, principalmente das turbinas (Walter, 1994). A curto e médio prazos não são consideradas reduções substanciais da demanda de vapor. O cenário de referência corresponde a valores médios atuais do setor sucro alcooleiro no Estado de São Paulo.

No estudo feito nesta tese, para efeito da análise econômica do sistemas BIG-CC cofiring (ver Capítulo 5), não foi considerado o emprego de bagaço excedente.

Tabela 2.8 Cenários para produção de bagaço excedente nas usinas - São Paulo

Cenários	Referência	I	II
Vapor de processo (kgv/tc)	500	485	420
Pressão de vapor (MPa)	2,1	2,1	3,1
Temperatura do vapor (°C)	280	280	400
Eficiência da caldeira	0,70	0,74	0,76
Eficiência das turbinas – eletricidade	0,66	0,71	0,73
kg de vapor/kg de bagaço	2,09	2,21	2,27
kg de vapor/kWh	14,4	13,4	7,9
Excesso de bagaço (%)	10	22	34
Disponibilidade de bagaço (PJ)	---	97	153

Hipóteses: (1) requerimentos elétrico e mecânico - 15 kWh e 12 kWh/t cana moída, respectivamente; (2) teor de bagaço - 260 kg/tc; (3) eficiência da turbo-moenda: 0,43; (4) pressão de escape: 0,25 MPa.

Capítulo 3

Avaliação de Desempenho de Sistemas BIG-CC Atmosféricos sob Diferentes Estratégias de Controle de Turbinas a Gás

Síntese

O presente capítulo é apresentado na forma de um artigo ("Performance evaluation of atmospheric BIG-CC systems under different gas turbine control strategies") submetido à publicação na revista Applied Energy. Os resultados apresentados no artigo foram obtidos durante o desenvolvimento desta tese.

As turbinas a gás de sistemas BIG-CC precisam ser adaptadas para uso de combustíveis de baixo poder calorífico, como é o caso do gás de gaseificação da biomassa. Alguma alterações no "hardware" da turbina, como na câmara de combustão, são necessárias. Mesmo com as alterações propostas as turbinas a gás são submetidas à condições atípicas de operação, em função do maior fluxo de massa de gases que, por sua vez, decorre do menor poder calorífico do combustível. Mantidos outro parâmetros de projeto e operação, o maior fluxo mássico só pode ser acomodado com elevação da pressão dos gases, resultando em maior relação de pressões no compressor. Por outro lado, a elevação da relação de pressões pode fazer com que o compressor seja perigosamente levado próximo ao limite de "surge", condição em que ocorre recirculação do ar e suas palhetas são submetidas à vibrações. Para que tal problema seja contornado as turbinas a gás precisam ser submetidas à estratégias de controle. Algumas estratégias são inclusive normalmente empregadas, mesmo quando a turbina queima combustíveis como o gás natural.

As estratégias de controle consideradas neste trabalho são: o "de-rating" da turbina, a extração de uma fração do ar à saída do compressor e o redesenho da seção de entrada do expansor. Resultados dessas três alternativas foram comparados à alternativa hipotética de operação das turbinas a gás sem controle da relação de pressões. O "de-rating" consiste na redução da temperatura máxima dos gases, o que deve ser feito de forma tal a que a máxima relação de pressões aceitável seja alcançada. É a opção mais simples e barata, e deve ser utilizada no curto prazo. A extração de ar dos compressores é um recurso utilizado nos sistemas IGCC, de gaseificação de carvão, e é mais adequado aos sistemas BIG-CC com gaseificação pressurizada. Para os sistemas baseados na gaseificação atmosférica suas vantagens são menos evidentes. Já o redesenho dos expansores é uma opção que só se justifica quando a tecnologia BIG-CC estiver com mercado consolidado.

Os resultados apresentados estão baseados na simulação computacional de ciclos BIG-CC de distintas capacidades. A modelagem de sistemas de capacidade distinta se justifica pelo estudo dos efeitos de escala descrito no Capítulo 5. Os resultados de desempenho dos ciclos com turbinas submetidas a "de-rating" são os piores, tanto considerada a potência gerada quanto a eficiência de geração. Por seu turno, os resultados da opção associada ao redesenho são os melhores, e são inclusive superiores aos do caso referência (operação da turbina a gás sem limite imposto à relação de pressões). Exceto o caso do "de-rating", os resultados obtidos têm a influência de um ajuste operacional imposto às caldeiras de recuperação de calor (HRSG), para que um nível mínimo de temperatura dos gases de exaustão fosse verificado.

Na primeira parte do artigo são analisadas as propriedades físicas e químicas do bagaço e das pontas e folhas. É feita a análise da adequação dessas biomassas para a operação de gaseificadores atmosféricos, bem como dos gases de gaseificação para operação em turbinas a gás. A análise foi feita exclusivamente a partir de informações disponíveis na literatura. Conclui-se que restrições mais sérias não devem ser observadas, sendo possível a gaseificação tanto de bagaço quanto de pontas e folhas em sistemas BIG-CC.

Performance evaluation of atmospheric BIG-CC systems under different gas turbine control strategies

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Abstract

This work aims at a performance evaluation of atmospheric BIG-CC (Biomass Integrated Gasification-Combined Cycle) systems operating under different gas turbine control strategies for the use of low calorific fuels. The considered fuel is a synthetic gas derived from sugar-cane residues. Control strategies analyzed are gas turbine de-rating, air extraction from the compressor and increasing the expander critical area. Results are compared to the hypothetical situation in which it is possible to accept any increase on gas turbine pressure ratio. Gas turbine de-rating is the worst control strategy both from the point of view of power production and thermal efficiency. Conversely, redesign of the gas turbine expander is the best option. In addition, in the first part of this paper the suitability of sugar-cane residues (bagasse and trash) for the production of gasified gas and its use in BIG-CC plants is investigated.

Keywords: BIG-CC technology; Gas turbine control strategies

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1. Introduction

The interest regarding BIG-GT/CC (Biomass Integrated Gasification-Gas Turbine/Combined Cycle) technology has increased. Following the pioneer demonstration CHP plant (6 MW_e and 9 MW_{th}) built in Värnamo (Sweden), and now decommissioned, other demonstration projects are in progress, such the one known as ARBRE (8 MW_e), in England, and the Energy Farm project (12 MW_e), in Italy. Despite the efforts towards engineering development and cost reduction, some technological drawbacks still have to be overcome. One of the main technological issues of BIG-GT/CC technology is concerned with gas turbines adaptation to low-heating-value fuels.

The use of biomass-derived gas imposes higher pressure ratio on gas turbine operation due to the larger mass flow led through the expander. Accepting an increase in pressure ratio might lead to dangerous reduction on compressor surge margin. Surge is a risky transient condition involving reversed flow through the compressor and can occur as the pressure ratio increases beyond some maximum safe value [2]. In these cases control strategies should be applied to keep the compressor far enough from the surge limit and under torque limits, as well as to avoid over speed [3].

Standard strategies of control can be used in order to make it possible for the gas turbine to run on gas from biomass. Gas turbine de-rating is the simplest control strategy and is the one chosen for the short-term market of BIG-GT/CC technology. Gas turbines are usually de-rated by imposing a lower burning temperature. Reduction of compressor pressure is a consequence of such action. As gas turbine firing temperature governs the cycle efficiency, there could be a strong penalty for the overall cycle efficiency.

Other strategies that can be imposed are just accept some extent of higher-pressure ratio, redesign of the expander [1] and the extraction of air at the compressor discharge. The latter has been extensively investigated for IGCC systems [4][5][6]. This strategy is used when IGCC air separation plant is located on-site with the gas turbine units so that air can be bled from the gas turbine to supply the air separation plant. The waste nitrogen from the air separation plant is recompressed for return to the gas turbine combustor [1].

The rise on pressure ratio under certain limits can be eventually accepted for the compressor of some industrial gas turbines [6]. However, problems concerned with increase of shaft torque and thermal loads on airfoils are yet expected making this strategy very aggressive to the equipment [1]. The extraction of air at the compressor discharge and the increase in the expander critical area are retrofitting options that would occur in the longer term as the market for BIG-GT/CC systems gets developed. On the other hand, increasing the critical area requires hardware modifications to the expander inlet nozzle vanes. This is the most expensive approach and a permanent change that could make the returning to natural gas more difficult [1].

This paper aim at assesses the impact of different gas turbine control strategies over the performance of BIG-CC power cycles. This work is part of a broader research aiming at investigate co-firing (burning a mix of natural gas and biomass-derived gas) as a mechanism to improve short-term BIG-CC cost-effectiveness. BIG-CC cycles are expected to achieve efficiencies around 40 per cent for atmospheric gasification of wood at modest scales [8][9] but further improvements are necessary. In fact, costs reduction seems especially possible by improving the conversion efficiency [8].

The biomass considered within this study is sugar-cane bagasse and sugar-cane trash (leaves and points of the plant). Bagasse is a residue of the sugar-cane crushing process and is relatively cheap. Trash is becoming increasingly available in Brazil due to the enlarging implementation of green cane harvesting.

2. The suitability of sugar-cane residues for BIG-CC technology

Physical and chemical properties of the biomass affect the suitability of the derived gas for BIG-GT/CC technology. Physical properties, such as size and density, affect handling and feeding systems. Chemical properties, such as composition, heating value and ash content, have a strong impact in gasification and cleanup systems.

2.1 Physical properties

A biomass particle size ≤5-cm allows for high efficiency conversion in fluidized-beds due to better mixing with the bed material and greater char conversion rates [10]. The size of sugar-cane trash particles depends on the machine used to chop it. Data presented in Table 1 corresponds to the use of a chaff cutter [11]. An advantage of bagasse is its small particle size – frequently lower than 5 cm – resulting from the crushing process in sugar factories.

Table 1. Physical characteristics of sugar-cane bagasse and trash

	Chopped Trash	Bagasse
Particle size	<1-10 cm (1)	<5cm (2)
Bulk density (kg m^{-3} db)	95-130 (3)	50-75 (3)
Moisture content (wt% wet)	30 (3)	50 (2)

Notes: 1. Chopped – leaves size obtained using a chaff cutter [11]
2. Bagasse available from sugar factories almost powdery
3. For loose leaves [11]
4. Copersucar [12]

The moisture content of biomass affects the degree of energy used for drying and the derived gas composition. Due to the crushing process, bagasse available at sugar-cane mills has higher moisture content than trash; in addition trash can be left on the field, achieving even lower moisture content.

Furthermore, the low bulk density and the cohesive characteristics of bagasse and cane trash can cause an accumulation of the fuel in the feeding system, creating difficulties for the flow into the gasifier. This constraint should be more serious for pressurized gasifiers and was a serious barrier during tests of an unit of 10 t/d performed in Hawaii till 1998. Trash has higher bulk density than bagasse. Typical values of some physical characteristics of sugar-cane bagasse and trash are presented in Table 1.

2.2 Chemical properties

Typical results of ultimate analysis of sugar-cane bagasse and sugar-cane trash are presented in Table 2. The chemical composition of the biomass feedstock has strong influence on the design of the cleanup gas section, that is an essential part of the BIG-CC system. Some inorganic elements present in the feedstock can cause corrosion in the equipment downstream and some are pollutants. Gas turbines, for instance, have very strict limits for particulates, alkali metals and condensable tars in the fuels delivered to the combustor in order to prevent erosion, fouling and corrosion of the gas turbine hot section [15][16].

Another matter of concern is the fuel-bound nitrogen that may be a significant source of NO_x emissions when biomass-derived gases are used in gas turbines. Chlorine and sulfur are also potential contaminants. Sulfur content can be quite high in trash that derives from plantations fertilized with vinasse [14]. However, the condensation of acids from chlorine or sulfur in the HRSG is not a problem as long as flue gases temperature is kept above 200°C [15].

Table 2. Ultimate analysis of sugar-cane bagasse and trash

% weight – dry basis	Bagasse [1]	Trash [2]
C	46.30	45.03
O	43.30	44.26
H	6.40	6.30
N	---	0.80
S	---	0.70
Cl	---	0.61
Ash	4.00	5.30
LHV [MJ/kg]	17.5	17.6

Source: 1. [13]
2. [14]

2.3 Contaminants and cleaning considerations

Considering trash or bagasse as feedstock, the composition of the bagasse- and trash-derived raw gas and its contaminant contents are not available in literature. The Swedish company TPS (Thermiska Processer AB) and the Brazilian COPERSUCAR recently performed gasification tests in an atmospheric air-blown gasifier similar to that considered in this paper. It is known that the results were positive, but more details are not available. Therefore, the following analysis regarding alkalis and fuel bound nitrogen is based on a comparison with other biomass feedstock.

2.3.1 Tars

Tars are heavy condensable organic compounds formed during gasification of biomass. They account for 0.5 to 1.5 per cent by mass of the product from a typical fluidized-bed gasifier, depending on the temperature. If tars condense on cool surfaces, severe operating problems can result, including constricted piping or clogged valves and filters [15]. There are several uncertainties regarding the maximum allowable tar levels for gas turbines, as manufactures do not list tar in their maximum allowance. Tars behave like an aerosol, a droplet and/or a particle. If this is the case, tar levels should be as low as possible to avoid erosion of the blades.

Tars often constitute an important energy component of the fuel gas that removing them from the gas would result in a loss of system efficiency. Following the proposed TPS technology, for this work it is considered tar is removed in a circulating fluidized-bed cracker that uses dolomite as bed material (see section 4.1). The dolomite acts as a catalyst breaking down large hydrocarbon molecules into smaller ones, that are lighter and more permanent compounds. As consequence of tar removal, it is possible to procedure gas cleaning at low-temperature without concerns of gas condensation. This second reactor leads to the production of gas with very low levels of tar so that wet scrubbing can be used with relatively little loss of chemical energy [15]. In the BIG-CC power plant here considered the temperature at which the gas enters the gas turbine is 370°C, which is in the range of temperatures (between 350-400°C) that avoid the condensation of some remaining heavy tars that might still be present in the gas.

2.3.2 Particulates

Particulates even in small quantities can cause turbine erosion [14]. According to Kloster et al. [17] for gas turbines the required gas quality regarding particles smaller than 5 μm is 30 mg/Nm³. Gas stream from biomass contains very small carbon-containing particles, which are difficult to be removed by cyclones. The suggested cleaning device for BIG-CC systems based on atmospheric gasification is a baghouse filter, followed by a scrubber that would help the removal even of very fine particles.

2.3.3 Alkalis

Alkali metals, such as sodium and particularly potassium, naturally exist in biomass. Part of these alkalis vaporizes depending on the content in the fuel and on the gasification conditions. Alkali metals could cause high temperature corrosion of turbine blades due to stripping off their protection layer and, for that reason, it should not exceed 0.1 ppm at the entry of gas turbine expander. According to Salo and Mojtahedi [18] tests carried out with a $15MW_{th}$ pressurized fluidized-bed gasification test rig in Finland for various biomass sources, including willow, wood and straw show that alkali levels in the clean syngas could be reduced to less than 0.1 ppm. This concentration was achieved with cooling and filtering. Cooling the gas to 350-400°C before the filter should be sufficient to condense the alkalis to be removed with the particulates. An additional wet scrubber essentially complete removal for the atmospheric fluidized-bed gasification.

As shown in Table 3, the content of potassium in ash composition of sugar-cane trash is lower than in wheat straw, one type of biomass that has been analyzed in the tests described by Salo and Mojtahedi [18]. Sugar-cane bagasse presents an even much lower content of alkalis as the watering during the process of crushing of sugar-cane remove these soluble contaminants. Based on such comparison, levels of alkali for bagasse and trash do not seem to be a problem for the use of sugar-cane residues in atmospheric gasifiers.

Table 3. Ash composition of various biomass sources

Oxide (%ash)	Bagasse	Trash	Wheat straw
SiO_3	46.61	57.38	35.84
Al_2O_3	17.69		2.46
TiO_2	2.63		0.15
Fe_2O_3	14.14	1.74	0.97
CaO	4.47	13.05	4.66
MgO	3.33	4.30	2.51
Na_2O	0.79	0.27	10.50
K_2O	4.15	13.39	18.40
SO_3	2.08	7.31	5.46
P_2O_5	2.72	2. 27	1.47
Undetermined	1.39	0.29	17.58
Total ash (% dry fuel)	2.44	5.04	13.00
Cl (% dry fuel)	0.03	0.22	2.02

Source: [19]

2.3.4 Nitrogen oxides – fuel bond nitrogen

During high temperature gasification of biomass, fuel bound nitrogen (FBN) can form pollutants such as ammonia (NH_3), hydrogen cyanide (HCN), and nitrogen oxides (NO_x) [20]. These compounds can poison catalysts or elevate NO_x emissions. Simulation and experiments carried out in Hawaii [20] have demonstrated that FBN from biomass is mostly partitioned in NH_3 and N_2 during gasification. Ammonia will then cause most of the emissions of fuel bound NO_x during the combustion of syngas in the gas turbine. Lietti *et al* [21] have investigated the oxidation of NH_3 and the NO_x formation during the catalytic combustion of gasified biomass fuels. The combustion led to the formation of significant amounts of NO_x, particularly NO, in contrast with the low-NO_x emission requirements of gas turbine applications. As ammonia is a soluble compound, it could be completely removed when it goes through the scrubber [15].

2.3.5 Nitrogen oxides – thermal nitrogen

The decisive factor affecting the formation of thermal NO_x is the flame temperature, which varies exponentially with this parameter [2]. When natural gas is used, the thermal nitrogen is a matter of concern for its high flame temperature. Using syngas from biomass thermal nitrogen is likely to be very low due to the lower flame temperature [15]. Cook et al. [22] carried out experiments for the combustion of low calorific gases and found that NO_x emissions could be correlated as a simple function of stoichiometric flame temperature for a wide range of heating values. In general, the flame temperature of low calorific gases are typically 500-1000K lower than the natural gas or distillate oils, so that thermal NO_x are not expected to be a problem in BIG-CC systems [23].

2.4 Syngas composition

Modeling the complex chemical kinetics that occurs in the gasifier is beyond the scope of this work. Here, raw syngas composition obtained from the gasification of sugar-cane residues was predicted based on a quasi-equilibrium model developed with ASPEN Plus© simulator. The procedure includes a set up step to avoid large distortions due to the quasi-equilibrium hypothesis. The results of this model for the gasification of a typical wood have been compared with data presented by Consonni and Larson [15] for the same biomass. This reference of comparison was chosen due to the accuracy of the results to the gas composition provided by technology developers. Results obtained from the model and the compositions of comparison are presented Table 4.

Table 4. Estimated raw syngas composition and composition of reference (% mol) – wood

	Estimated composition	Consonni and Larson [15]
H_2	15.0	14.8
CO	18.0	19.8
CO_2	9.5	10.4
CH_4	2.4	2.6
C_2H_2	----	0.9
C_6H_6	0.6	----
H_2O	11.8	11.6
N_2	42.1	39.1
Ar	----	0.5
H_2S	0.1	-----
NH_3	0.3	-----
tars	0.2	0.3

In order to estimate syngas composition from sugar-cane residues the same procedure was applied, starting from a raw syngas composition predicted by ASPEN model. As the ultimate analysis of bagasse and trash are quite similar, the composition for the raw syngas was considered to be the same for both biomasses. Clean syngas composition was predicted considering that all contaminants are removed during the cleanup process and that syngas is saturated at the exit of the scrubber. Table 5 presents estimated raw and clean syngas compositions.

Table 5. Estimated raw and clean syngas composition (%mol) - sugar-cane residues

	Raw syngas	Clean syngas
H_2	14.99	16.69
CO	17.95	19.98
CO_2	9.42	10.49
CH_4	2.36	2.63
C_6H_6	0.30	0.33
H_2O	11.75	3.24
N_2	41.90	46.64
Contaminants	1.33	------

3. Gas turbine operation with low calorific fuel

3.1 Required modifications on gas turbines

Natural gas and light oil distillates are the preferred fuels for gas turbines but many other fuels have been used successfully, including LCV natural gases, naphtha, condensates and gases from iron and steel industries with heat content as low as 3 MJ/m^3. Some modifications should be necessary for the use of LCV fuels in a gas turbine originally designed for the use of natural gas. These modifications comprise gas turbine layout for the changed mass flow, fuel delivery/injection system, fuel nozzles and fuel manifold and combustion chamber [24][25]. Burning LCV fuels the can type combustors used in many industrial gas turbines generally provide adequate cross section and volume for complete and stable combustion with acceptable pressure drops [9]. The combustion system for the use of LCV fuels has to be modified, though.

A study by De Kant and Bodegom [7] suggests that for the use of a biomass-derived gas the combustion chamber has to be completely replaced.

There has been no commercial operating experience with LCV fuels in aero-derivative gas turbines that utilize more compact combustors, but the GE LM2500 has been modified for the operation with biomass derived-gas [9][24]. In this case it is proposed that the expander of the steam injection model be used in order to better accommodate the larger gas flow. Other modifications done on this gas turbine include: a larger swirler to accept the new fuel nozzle, fuel nozzles with dual inner circuits for start natural gas and syngas delivery to the combustor, and syngas manifold to deliver fuel to the manifold [24].

The issue of combustion stability is closely related to the low heating content of the syngas. A combined cycle power plant built in a steel mill in Taranto, Italy, had the combustion system of its gas turbines modified to operate a gas mixture with a LHV as low as 6.2 MJ/Nm^3 [26]. The LHV of biomass-derived gases ranges between 5-6 MJ/Nm^3 for directly heated gasifiers [9]. General Electric carried out some work on the combustion of a gas derived from air-blown atmospheric gasification having a heating value of 3.7 MJ/Nm^3, provided there are some hydrogen in the gas. Experiments performed with a modified combustor can of a Typhoon gas turbine in Delft Technical University, The Netherlands, have achieved stable combustion of biomass-derived gas with a heating value between 2.5 and 3 MJ/Nm^3 [23]. The gas derived from sugar-cane residues considered within this work has a heating value close to 6 MJ/Nm^3, so that no flame stability problems should be expected.

Hydrogen content on syngas is another important issue for BIG-CC systems. Hydrogen has a much higher flame propagation speed than CO or CH_4, the main other combustible components in biomass-derived gas, therefore, favoring the flame stability. However, higher hydrogen content increases the risk of back stream flame propagation for the case of dry low NO_x combustion chamber [7]. General Electric specifications for its dry-low NO_x combustion systems allow no hydrogen in the fuel due to the design of the combustion can. ABB constrain the hydrogen content to a 5 per cent (per volume) for its dry-low NOx systems. As presented in Table 5 the predicted hydrogen content for the syngas considered in this work is much higher than such limit.

An alternative for NO_x control in gas turbines is the use of water/steam injection. The problem is that more and more gas turbines are being equipped with dry-low combustors directly at the factory and, hence, high hydrogen content might represent a drawback when a machine is adapted for biomass-derived gas. Before further tests are carried out, gas turbines for BIG-CC should be restricted to models with water/steam injection for NO_x control, an option that can be required with the manufacturer. Moreover, thermal NO_x is not expected to be a problem for BIG-CC systems due to low flame temperature as previously mentioned.

3.2 Strategies for the use of LCV fuels in gas turbines

Taking into account critical area is a hardware constant, the increase on mass flow due to the use of LCV fuels can only be accomplished through an increase on gas pressure and/or a decrease on gas temperature at the inlet of gas turbine expander (see item 4.3.1). Conversely, as previously state, accepting the increase of the compressor pressure ratio at some extent is one of the ways to operate gas turbines with biomass-derived gas.

On the other hand, it is well known that the decrease on gas turbine maximum temperature leads to undesirable penalties for the cycle performance. However, this is the simplest strategy for the use of derived-gas from biomass in gas turbines that have been designed for natural gas. Decreasing the maximum temperature means de-rating the gas turbine, i.e., there is a reduction on power production accompanied by a decrease on gas turbine thermal efficiency. The control strategy associated to gas turbine de-rating leads the compressor pressure ratio down to a safe margin from the surge limit by means of controlling its maximum temperature.

Another control strategy is blasting air from the compressor to reduce the mass flow at the expander entrance. Blowing off air from the compressor is an option eventually used for surge control of gas turbines even when natural gas is burned [2] but the continuous extraction of air to allow the use of LCV fuels should require some retrofit [5]. This strategy is more suitable for BIG-CC systems based on pressurized gasification as the extracted air can be directly injected into the gasifier. Compressor blast-off would be definitely simpler than redesign the first stage of the expander vanes that is another alternative for gas turbine adaptation. The latter would mean a dramatic and expensive retrofitting. A brief comparison of these four strategies is presented in Table 6.

Table 6. Strategies for the use of LCV fuels in gas turbines

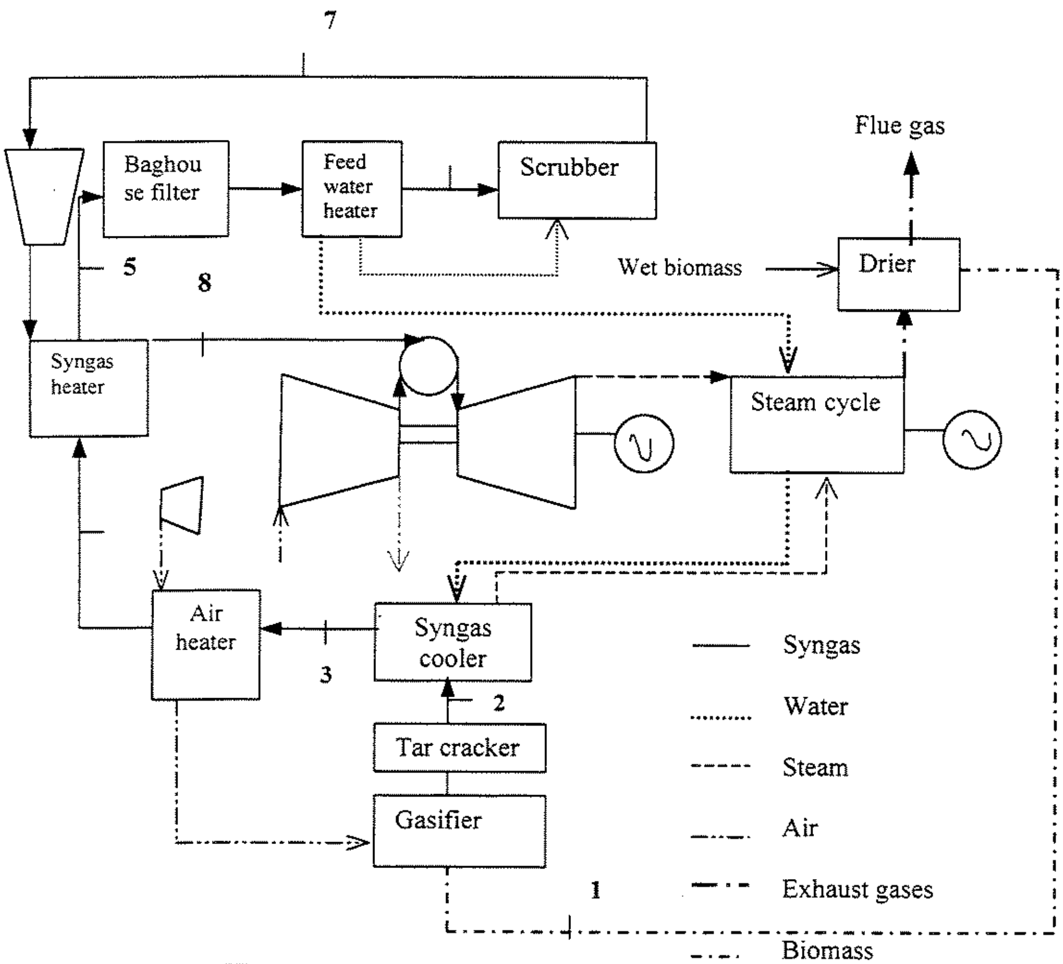
Strategies	Description	Advantages	Disadvantages
Accepting the increase on pressure ratio	The compressor is operated at a higher pressure ratio that leads to a small reduction on air mass flow	Excluding GT retrofitting is the option that leads to maximum power and efficiency	More technically aggressive due to increased thermal loads and torque transmitted
De-rating	Reduction of gas turbine firing temperature	The simplest strategy as it incurs in no retrofitting	Most severe penalties for GT efficiency and power production
Compressor blast-off	Air bled from the compressor discharge	Small effect on power production. Retrofitting allows further return to natural gas	Conversion might affect the proper distribution of hot air to the combustors and cause frictional loss in the flow region
Expander inlet nozzle redesign	Hardware modifications to the expander inlet nozzle	Leads to the best GT performance	It is a permanent modification making the return to natural gas more difficult. The most expensive approach

4. Power system description and modeling procedure

4.1 Power system description

The power plant here considered is based on biomass gasification that occurs in an atmospheric air-blown gasifier similar to those developed by the TPS. This type of gasifier is technically proven and likely to reach a commercial status on the short-term. TPS technology is being used in the ARBRE project and has been selected for the demonstration unit that will be built in Brazil (32 MWe) [27]. It is considered that before the gasifier the biomass moisture content should be reduced to 15 per cent by using flue gas from the HRSG and that drying design conditions requires a minimum flue gas temperature (200°C). Gasification occurs with air injection in a circulating fluidized bed (CFB) fuel at 2 bar. A second CFB reactor – the tar cracker – follows the gasifier. This reactor operates as a slightly higher temperature and cracks the tar in lighter hydrocarbons. After the tar cracker, the raw syngas is cooled and the heat is sequentially recovered to boost steam generation, to preheat the blast air, the syngas itself (before it enters the gas turbine), and the feed water for the boiler. After cooling, a baghouse filter removes the particulates and remaining components are removed in a wet scrubber.

The gas turbine exhaust gases are recovered at an unfired HRSG. It was assumed that for all three combined cycles considered in this work steam is raised in just one pressure level. It is well know that in conventional medium to large combined cycles thermal efficiencies are increased with steam production in two or three pressure levels. Medium pressure steam re-heating is also ordinary in these cycles. The hypothesis of a single pressure HRSG was assumed because only marginal gains can be achieved with multiple pressures in BIG-CC cycles [9]. Figure 1 shows a schematic drawing of the cycle. The light -colored line represents the option of blasting air from the gas turbine compressor.



Flow	Parameters	
1	15% moisture	
2	870°C	0.22 MPa
3	590°C	0.198 MPa
4	432.8°C	0.194 MPa
5	237°C	0.190 MPa
6	98°C	0.186 MPa
7	40°C	0.17 MPa
8	370°C	0.3 MPa

Figure 1. Scheme of the BIG -CC cycle considered and parameters at selected points

4.2 Analyzed gas turbines

The impact of gas turbine control strategies over the performance of BIG-CC cycles is investigated for three systems of different capacities. The smallest cycle is based on a gas turbine that is representative of aero-derivative engines. The so called medium and large cycles are based on typical heavy frame gas turbines. Some characteristics of three commercial General Electric gas turbines were used for the cycle modeling in each case: LM2500, PG6101(FA) (Frame 6) and PG7001 (Frame7). LM2500 was chosen for the range of plants of smaller capacities because, as previously mentioned, has been already adapted for BIG-CC units and, as second reason, because aero-derivative machines have higher efficiency than industrial gas turbines up to $50MW_e$. GE PG6101 produces about $70MW_e$ at ISO basis and its design allows the use of LCV fuels [27]; its pressure ratio is adequate for combined cycles and was here considered representative of machines with moderate turbine inlet temperature – TIT. On the other hand, for the cycle of largest capacity it was chosen a gas turbine with TIT close to the maximum a commercial turbine can operate (about 1400°C) [2] and a pressure ratio that is suitable for combined cycles (around 15). Parameters of the three gas turbines considered within the modeling are presented in Table 7.

Table 7. Main parameters of considered gas turbines operating with natural gas at ISO basis

Gas turbine	Air flow rate [kg/s]	TIT – Turbine inlet temperature [°C]	Pressure ratio	Fuel flow [kg/s]	Exhausting temperature [°C]	Power (MW)
Aero-derivative	68.2	1258	18.9	1.3	529	21.9
Medium size	192.3	1288	14.9	4.3	597	70.1
Large size	409.8	1371	14.8	9.2	583	159.0

Source: [29]

Gas turbine parameters that are not available in open literature have been estimated during the first step of the modeling procedure – a tuning procedure that uses parameters provided by manufacturers. Additional parameters that were considered within modeling are listed in Table 8.

Table 8. Main estimated gas turbine parameters

Gas turbines	Isentropic efficiency		Mechanical	Alternator	Cooling	Auxiliary
	Expander	Compressor	efficiency	efficiency	fraction	power [kW]
Aero-derivative	0.87/0.80 [1]	0.88	0.99	0.996	0.122	275
Medium size	0.87	0.90	0.98	0.985	0.089	921
Large size	0.90	0.90	0.98	0.992	0.187	9870

Note: 1. For the high pressure and low pressure expander sections, respectively

4.3 Modeling details

4.3.1 Off-design gas turbine modeling

Predicting gas turbine performance when LCV fuel is burned requires a procedure for off-design modeling. For a given gas turbine, the compressor pressure ratio is only known for the reference case (ISO). As long as atmospheric properties change, de-rating is imposed or fuel changes, compressor pressure ratio varies. An essential feature of a gas turbine off-design procedure is its ability in evaluating new compressor pressure ratio. The basic assumption of the procedure utilized in this work is that the flow at the inlet of the gas turbine expander is choked regardless the fuel. This is a very reasonable assumption for a wide range of gas turbine operation conditions [2]. The mass flow relation for choked flow of an ideal gas applied at the inlet of the expander – equation (1) – allows the calculation of the new compressor pressure ratio. Depending on the adopted strategy for the use of LCV fuels (see item 3.2), parameters to be changed in equation 1 are the gas mass flow, the gas temperature or even the critical area. The magnitude of changes will depend on a pre-determined safe margin from the surge limit.

$$m = p.A^{*}\frac{C}{\sqrt{T}} \tag{1}$$

where p is the total pressure, A^{*} is the critical area and T is the gas temperature. All gas properties are estimated at the expander entrance. The parameter C is given by

$$C = \sqrt{\frac{Mol.\gamma}{R}\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{\gamma-1}}} \tag{2}$$

where Mol is the gas molecular weight, R is the universal gas constant and γ is the ratio between specific heats of the gas. The procedure imposes that equation (1) should be first applied to estimate the critical area based on the reference ISO case in which natural gas is burned. The estimated value is then further used as a constant.

The difficulty in predicting gas turbine performance at off-design conditions comes from the fact that actual compressor maps are not available in open literature and, hence, the actual relation between compressor pressure ratio and the air mass flow cannot be easily defined. In this work a generic compressor map, as presented in Figure 2, is assumed for the calculations. The procedure simply establishes for a given running line a polynomial function relating the compressor reduced mass flow ($m.T^{1/2}/p$, with all parameter evaluated at the entrance of the compressor) to its pressure ratio. Thus, for a given pressure ratio (e.g., for the gas turbine operation with syngas) it is possible to calculate the corrected air flow.

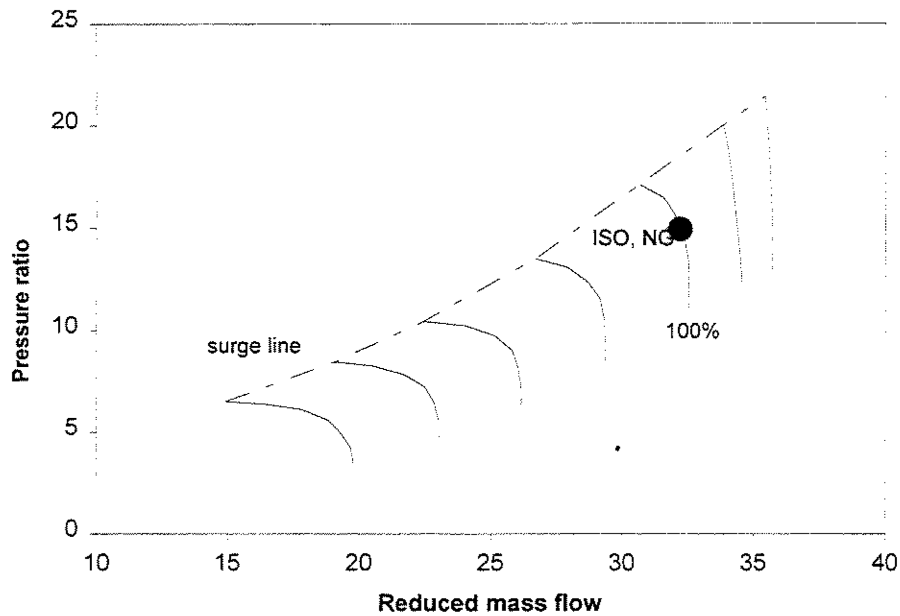


Figure 2. Typical axial compressor map of gas turbines

For calculations purpose it is assumed that the compressor ever operates over the "running line 100%" for both natural gas and biomass-derived gas. It is accepted that the operation with natural gas corresponds to a compressor map variable (CMV) equal to 0.75. CMV is defined by equation (3) and indicates how far compressor operation is from the surge limit (CMV =1). It is also assumed that the limit for continuous operation of industrial gas turbines corresponds to a CMV = 0.95. In fact, the compressor characteristic of industrial gas turbines can cope with a large increase on the pressure ratio [7]. On the other hand, aero-derivative engines have a more critical compressor operation and control since the compressor shaft is not connected to a generator and therefore spins freely [3]. The maximum pressure ratio for the aero derivative gas turbine was assumed to be the same as that proposed by Consonni and Larson [9], which corresponds to a CMV of 0.85.

$$\mathrm{CMV} = \frac{\mathrm{PR}-1}{\mathrm{PR_S}-1} \tag{3}$$

where PR is the compressor pressure ratio and PR_s the estimated pressure ratio that corresponds to the surge limit for a given running line.

4.3.2 Other assumptions

Other relevant assumptions for the thermodynamic simulation of gas turbines are briefly described bellow. Main assumptions for the power cycle modeling are described in Table 9.

Table 9. Main assumptions adopted for calculations for all simulated case

HRSG & steam cycle	• Approach ΔT = 30°C; pinch point ΔT = 15°C. • Heat losses 0.7% of heat released by gas; pressure drop at the gas side 3kPa, pressure drop at the superheater 10%. • Overall isentropic efficiency of steam turbine 0.75. • Steam pressure at the condenser 9.6 kPa. • Water outflow from deaerator: 488 kPa, 120°C. • Total auxiliary power = 160% of the estimated power for the pumps (isentropic efficiency 0.65). • Cycle based on aero-derivative GTs: Steam raise at 8 MPa, 480°C at the reference case[1]. • Medium and large cycles: Steam raised at 10 MPa, 538°C at the reference case.
Gasifier	• Outlet syngas temperature 870°C, outlet pressure 0.20 MPa, $\Delta p=0.02 MPa$
Dryer	• Biomass dried from 50% to 15% mc, exiting at 70°C
Heat exchangers	• $\Delta p/p$ 2%; heat losses equivalent to 2% of heat transferred
Syngas compressor	• Organic and electric efficiencies 90%.
Air compressor	• Polytropic efficiency 80%. • Organic and electric efficiency 90%.
Ambient air	15°C, p=0.1013 MPa; humidity 60%

Note: [1] In fact, steam temperature varies according to the strategy used to burn syngas in gas turbines.

The set of equations modeling energy conversion inside the main components of a gas turbine (compressor, combustion chamber and expander) is not presented here. Basically, compressor and expander equations are defined for polytropic processes of known efficiency allowing the evaluation of gas outlet temperature and the power evolved with the compression and the expansion. Compressor equations are functions of the inlet parameters (air temperature, pressure and mass flow), the compressor pressure ratio and the isentropic efficiency. Conversely, expander equations are function of turbine inlet parameters (temperature and pressure), expander pressure ratio (different from compressor pressure ratio due to pressure losses at the combustion chamber) and the isentropic efficiency [30].

Due to changes on pressure ratio, corrections on isentropic efficiencies for the compressor and the expander are done based on the hypothesis of constant polytropic efficiency for both devices [2]. Temperatures of air and gas at outlet of these devices are then recalculated.

The fuel input is calculated through an energy balance at the combustion chamber, imposing that a specified maximum gas temperature should be verified. The maximum gas temperature is either evaluated as function of the known turbine inlet temperature or as the specified de-rated temperature to accomplish to surge control. Dissociation of combustion gases is not considered within the calculations. In atmospheric BIG-CC cycles the syngas is supposed to be preheated after the cleanup process helping on combustion stability. Thus, the input of energy regarding the syngas is not only due to its chemical energy, being its sensible heat an important share of the total amount.

The simulation model utilized in this paper to deal with gas turbines is simplified regarding the recalculation of cooling air fraction. However, this simplification does not have strong influence on the results, not affecting the conclusions further presented.

6. Simulation results

Calculations were performed for the three cycles for each of the considered gas turbine control strategies. The effects of each strategy over the cycle performance are investigated bellow.

6.1 Increasing the compressor pressure ratio

This is not in fact a control strategy but, in terms of machine performance, it is a good basis of comparison since no limits are imposed to the gas turbine operation. Within the simulation, in order to keep the exhaust gases at the minimum drying design conditions (200°C), steam generation rate had to be controlled. Simulation results of BIG-CC cycles for this case are presented is Table 10 along with results of equivalent cycles operating with natural gas (in parenthesis). The increased mass flow going through the expander leads to considerable increase on gas turbine and on steam power cycle vis-à-vis the correspondent configuration using natural gas. The increment in power production more than compensate the power requirements for the syngas compressor so that net power production is higher than the natural gas case. The overall efficiency is, however, considerably lower for biomass-derived gas as the increase in power is accompanied by an increase in energy input.

Table 10. Simulation results for BIG-CC cycles considering increased gas turbine pressure ratio – correspondent results for natural gas in parenthesis

Gas turbines	Net power (MW)	Thermal efficiency (%)	GT Power (MW)	Steam cycle power (MW)	Gas turbine pressure ratio	Fuel flow (kg/s)	Syngas compressor (MW)
Aero-derivative	34 (29)	39 (45)	31 (21.5)	12 (8)	21 (17.5)	14.5 (1.37)	7.4
Medium Size	105 (94)	41 (46)	93 (67)	38 (28)	17 (14.9)	43.5 (4.30)	20.0
Large Size	235.4 (206)	43.2 (49)	210.4 (153)	80 (53.4)	17 (14.8)	92.2 (8.90)	42.3

6.2 De-rating

This control strategy leads to the reduction on the gas turbine output power by imposing a lower burning temperature. De-rating impacts on the compressor pressure ratio by reducing gas temperature, that is accompanied by some reduction on mass flow as well. Despite considerable penalties on power and on thermal efficiency, both from the point of view of the gas turbine and the whole plant, this is the most likely strategy for the use of LCV fuels in the short term due to its simplicity. Yet, some slight increase in gas turbine power due to the larger mass flow is observed when compared to the results of natural gas case. Gas turbine de-rating also impacts the performance of the bottoming steam cycle as the amount of steam raised and its temperatures are reduced. Table 11 presents simulation results obtained in this work.

Table 11. Simulation results for BIG-CC cycles considering gas turbine de-rating

Gas turbines	Net power (MW)	Thermal efficiency (%)	GT Power (MW)	Steam cycle power (MW)	Gas turbine pressure ratio	Fuel flow (kg/s)	Syngas compressor (MW)
Aero-derivative	24.0	36.0	22.7	8.5	19.3	11.4	5.6
Medium size	87.0	39.0	77.5	31.7	16.4	38.0	17.0
Large size	194.0	41.3	176.0	65.0	16.2	75.7	36.0

6.3 Compressor blast-off

As previously mentioned, blasting air from the compressor is a more suitable strategy for a BIG-CC configuration with pressurized gasification, as the high pressure air could be blasted into the gasifier. For the case with atmospheric gasification, the extraction of air represents a loss of power if there is no utilization for the compressed air exergy. In fact, the air blasted from the compressor could be used to generate more power in another expander, but this option was not considered for this evaluation. In this paper compressor blast-off was imposed for each gas turbine up to the level in which compressor pressure ratio reaches the estimated maximum value for gas turbine continuos operation.

Simulation results show that net power production is about the same as when natural gas is considered. Comparing to the de-rating case there are considerable gains on power (around 20 per cent) but marginal gains on thermal efficiency (around 5 per cent). However, the extraction scheme requires some simple retrofit and an economic assessment should be carried out to evaluate whether performance gains compensate the investment or not. Simulation results for this control strategy are presented in Table 12.

Table 12. Simulation results for BIG-CC cycles considering compressor blast-off

Gas turbines	Net power (MW)	Thermal efficiency (%)	GT power (MW)	Steam cycle power (MW)	Syngas flow (kg/s)	Air blast-off (kg/s)	Syngas compressor (MW)
Aero-derivative	29.0	37.0	24.0	11.4	13.3	5.6	6.5
Medium size	97.8	39.8	83.7	37.4	41.9	13.0	19.0
Large size	217.0	42.0	189.0	77.3	88.6	27.0	40.0

6.4 *Retrofitting the expander*

Retrofitting the gas turbine expander is supposed to correspond to its redesign with a larger expander area to cope with larger gas flow that goes through the gas turbine. Results that corresponds to this strategy have been estimated by increasing the critical area A^* in equation (1). For each gas turbine the new critical area was estimated as the one that allows compressor operation at nominal (ISO) pressure ratio. Gas turbine temperatures were also supposed to reach its maximum in each case. General sense, results for thermal efficiency are about the same the case that corresponds to accept larger pressure ratio. On the other hand, better results regarding power are obtained. Table 13 presents simulation results obtained in this work.

Table 13. Simulation results for BIG-CC cycles considering retrofitting the gas expander

Gas turbines	Net power (MW)	Thermal efficiency (%)	GT Power (MW)	Steam cycle power (MW)	Syngas flow (kg/s)	Increase in A* (%)	Syngas compressor (MW)
Aero-derivative	35.0	40.0	31.0	12.6	14.7	22[1]	7.2
Medium size	113.3	41.3	97.2	42.6	47.0	22	20.1
Large size	251.0	43.4	219.0	88.0	98.0	21	42.0

Note: 1. Total increase includes the critical area enlargement for the modified LM2500 from which some of the parameters are taken for the simulation.

6.5 *Comparison of results*

A comparison amongst the simulation results for the three-modeled cycles is performed in Figures 3 and 4. The reference case for comparison corresponds to the hypothetical case in which there is no constraint for the rise of compressor pressure ratio, i.e., performance results presented in Table 10 for BIG-CC cycles correspond to 100 per cent in Figures 3 and 4.

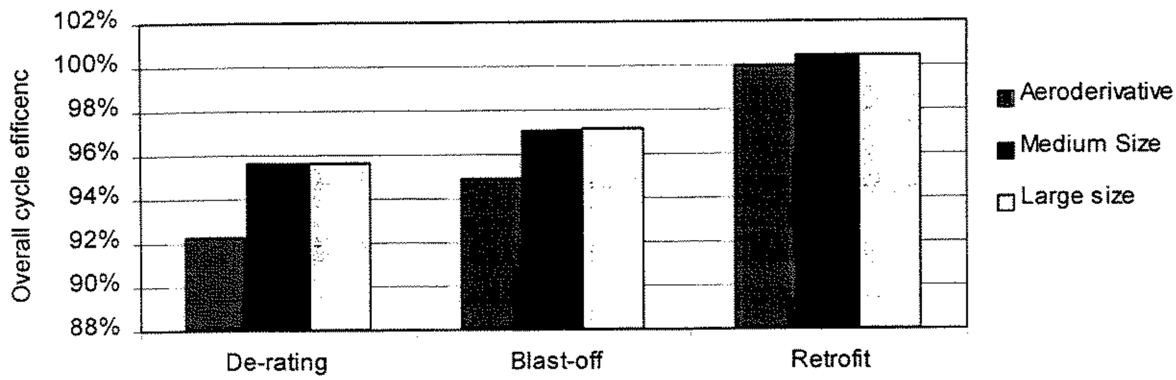


Figure 3. Results on thermal efficiency for different gas turbine control strategies in comparison to the reference case

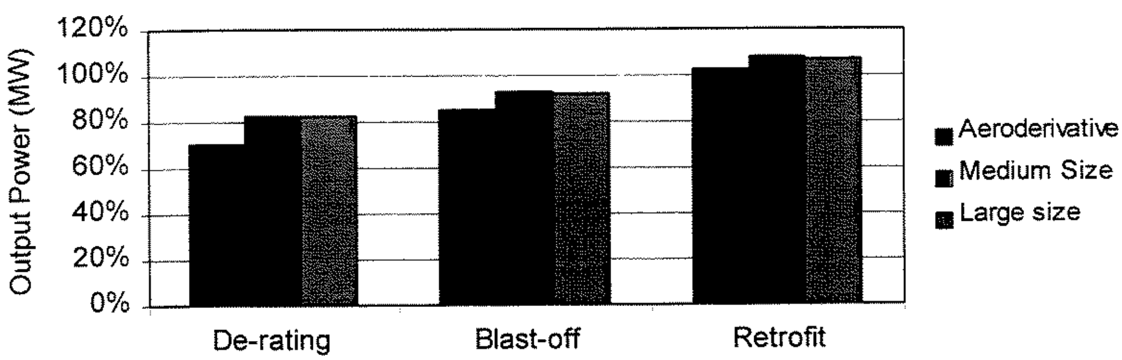


Figure 4. Results on power production for different gas turbine control strategies in comparison to the reference case

Retrofitting of gas turbine expander is clearly the best strategy both from the point of view of power production and plant thermal efficiency, leading to results even better than the reference case. For instance, when strategy based on enlarged expander area is applied, the gains with output power can be as high as 8 per cent. Conversely, gas turbine de-rating is the worst strategy, especially from the point of view of power production. For the aero-derivative case, for example, net power produced could be only 70 percent the one produced in the reference case. Compressor blast-off presents results slightly better than the strategy based on de-rating, probably do not justifying additional costs on gas turbine retrofit.

Worst simulation results with respect to performance were obtained for the power plant based on aero-derivative gas turbine. These results have the influence of simulation hypothesis used regarding the margin from the compressor surge limit. As similar hypothesis were used for the simulation of industrial gas turbines (results identified as medium and large sizes) and nominal pressure ratio are quite similar in both cases, performance penalties for them are of the same magnitude. Comparing aero-derivative with industrial gas turbines, performance differences are clear for the de-rating strategy, being the difference reduced with blast-off and even negligible when retrofit is applied. The reason is that within the simulation to achieve the imposed limit on pressure ratio it was necessary to reduce more the maximum temperature in the aero-derivative case (down to 90 per cent of its maximum) vis-à-vis in the industrial cases (down to 93 per cent).

Gains regarding thermal efficiency of the blast-off option vis-à-vis de-rating could be as high as 6 per cent for the aero-derivative case if there were no lower limit for the HRSG exhaust temperature. Because of the drying design constraint, thermal efficiency is only 3 per cent higher. Also for the gas turbine retrofitting the gains are reduced due to the drying constraints.

7. Conclusions

This work aimed at a performance evaluation of atmospheric BIG-CC cycles of different capacities fuelled by sugar-cane derived gases. Regarding syngas suitability for use in gas turbines, most of the constraints concerned to the physical and chemical properties of sugar-cane bagasse and trash seem to be potentially overcome. Considering a low density biomass such as sugar-cane residues, feeding systems of gasifiers remains a critical barrier, and its specially true for pressured gasifiers. Gas cleanup systems should be effective to fulfill strict requirements of gas turbines regarding particulate, alkali and tars.

From the point of view of power plant performance, strong penalties are predicted due to the strategies of surge control imposed to gas turbines. Owing to the modeling hypothesis adopted, stronger penalties are expected to power plants based on aero-derivative gas turbines rather than on those based on heavy industrial machines.

For all modeled cycles it is clear that gas turbine de-rating is the worst strategy for the use of LCV fuels, despite the fact it should be used in a large extent in the short term. When de-rating is applied, the thermal efficiency of BIG-CC cycles can be lowered to 92 per cent of the value of reference case (no compressor surge control on the gas turbine) or to 80 per cent of the efficiency value on natural gas. Even stronger losses are observed for the output power, as gas turbine de-rating can result on a 30 per cent power reduction at the worst case (aero-derivative case) and by 20 per cent at the best.

Conversely, redesign of the gas turbine expander is clearly the best strategy and would be used as long as the market for BIG-CC technology gets developed. As gas turbine constraints are reduced, power cycle can take full advantage of a larger mass flow. Results for this option could be even better if no constraint is imposed on minimum HRSG exhaust temperature.

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Capítulo 4

Cofiring de Gás Natural e Gás de Biomassa em Sistemas de Gaseificação de Biomassa Integrada a Ciclos Combinados

Síntese

O presente capítulo é apresentado na forma de um artigo ("Cofiring of natural gas and syngas in biomass integrated gasification / combined cycle systems") submetido à publicação na revista Energy: The International Journal. Os resultados apresentados no artigo foram obtidos durante o desenvolvimento desta tese.

No Capítulo 3 foi demonstrado que as turbinas a gás de sistemas BIG-CC precisam ser adaptadas para a queima de gases de baixo poder calorífico. Mais que isso, a necessidade de impor recursos de controle às turbinas penaliza o desempenho das instalações, tanto do ponto de vista da potência gerada quanto da eficiência de geração. Tal situação é particularmente verdadeira no caso do uso do "*de-rating*", que é o recurso que deve ser utilizado a curto prazo. O artigo que corresponde ao presente capítulo apresenta resultados da opção cofiring considerada neste trabalho, ou seja, a queima conjunta de gás natural e gás de gaseificação da biomassa. Os resultados obtidos são comparados aos resultados apresentados no capítulo anterior.

Um procedimento de simulação computacional foi utilizado. Os mesmo ciclos BIG-CC simulados no caso do uso exclusivo de gás de gaseificação da biomassa foram considerados. O procedimento de simulação foi aplicado para diferentes percentuais de adição de gás natural à mistura combustível, de forma a que pudesse ser determinado qual a composição que implica melhor desempenho. Quando necessário, foi considerado como recurso de controle das turbinas a gás o "*de-rating*", por ser a alternativa mais simples e barata. Resultados do estudo mostram que a operação ótima dos ciclos corresponde a um percentual de gás natural na mistura que é o mínimo para que não mais seja imposto "*de-rating*" à turbina a gás. Nessas condições a turbina opera com sua máxima temperatura, com a máxima relação de pressões aceitável, e pode-se tirar máximo proveito do incremento no fluxo mássico de gases.

Da comparação dos resultados da opção cofiring com os que correspondem ao uso exclusivo de gás de gaseificação da biomassa, conclui-se que com a adição de gás natural à mistura tem-se ganhos na potência total produzida e na eficiência de geração elétrica. Essa conclusão é válida para ciclos BIG-CC nos quais as turbinas a gás são submetidas à "*de-rating*". Já no caso da comparação com ciclos BIG-CC com turbinas a gás redesenhadas, o cofiring apresenta vantagens para certos percentuais de gás natural na mistura, mas desvantagens na comparação feita em função da capacidade de geração. Conclui-se que, exclusivamente do ponto de vista do desempenho, a cofiring é uma boa opção para o curto prazo, mas não necessariamente para o longo prazo.

Outra vantagem da opção cofiring está no fato de que muitas das modificações requeridas nas turbinas a gás de sistemas BIG-CC, quando do uso exclusivo do gás de gaseificação, poderiam ser evitadas. Por outro lado, as câmaras de combustão teriam de ser necessariamente adaptadas para a injeção e queima de dois combustíveis. As modificações requeridas são analisadas na primeira parte do artigo. Também são analisados os efeitos da adição do gás natural à mistura do ponto de vista das emissões de óxidos de nitrogênio. Conclui-se que deve haver aumento da temperatura de chama, o que deve favorecer a formação dos óxidos. Por outro lado, haverá uma redução do teor de hidrogênio no combustível, mas talvez não a ponto de permitir a utilização dos sistemas "*dry-low* NO_x".

Cofiring of natural gas and syngas in biomass integrated gasification / combined cycle systems

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Abstract

This work aims at evaluating cofiring of gas-derived from biomass and natural gas in combined cycles. Cofiring is here suggested to deal with some initial technological drawbacks of the main primer mover – gas turbines – of BIG-GT (Biomass Integrated Gasification/Gas Turbine) plants. De-rating is the simplest control strategy that allows continuous gas turbine operation with low calorific value – LCV – fuels, but imposes sever penalties on cycle power and efficiency. The proposed biomass gas is derived from sugar-cane residues, being its LHV around to 6MJ/Nm^3. Modeling results show that for shares higher than 35-50 per cent of natural gas (energy basis) no de-rating would be necessary. At these shares the efficiency of electricity generation is not substantially reduced vis-à-vis the reference case. Another important outcome is the peak in power that occurs for fuel mixtures that are slightly higher than those that offsets de-rating. Furthermore, other advantages of cofiring are associated with the small hardware modifications

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required on gas turbines. A comparison between the cofiring strategy and potential improvements related to the retrofit of gas turbines for LCV fuels is also carried out.

Keywords: Cofiring, electricity from biomass, BIG-GT technology;

1. Introduction

The BIG-GT (Biomass Integrated Gasification/Gas Turbine) technology has been considered to enhance biomass use as it could allow substantial improvements on the efficiency of electricity production. While conventional biomass power plants based on steam cycles have efficiencies in the 15-20 per cent range [1], BIG-CC cycles (the same principle of biomass gasification integrated to a combined cycle) are expected to achieve efficiencies around 40 per cent for wood and atmospheric gasification at modest scales [2][3]. Demonstration projects aiming at engineering development and cost reduction are in course. The first unit of such technology – a CHP plant (6 MW_e and 9 MW_{th}) based on pressurized gasification of wood residues and chips – has operated in Värmano (Sweden) from 1996 to 1999. A combined cycle unit of 8 MW_e net capacity is under construction in Yorkshire, UK (ARBRE project), based on atmospheric gasification of short rotation coppice and forestry waste. Other demonstration units are being considered, being the largest one expected to be built in Bahia, Brazil, for 32 MW_e.

Cycle efficiency is a crucial parameter for the cost-effectiveness of BIG-CC systems. One major technological drawback for the first generation of BIG-CC units is due to the penalties on efficiency resulting from the use of low calorific value – LCV fuels in gas turbines that have been designed for natural gas. Most of the losses come from control strategies applied to the gas turbine to keep the compressor operation safely beneath the surge line, that is its limit of stable operation. Compressor surging is associated with a sudden drop in delivery pressure and with violent aerodynamic pulsation, which is transmitted throughout the whole machine [4]. The rise in surge risk is associated with the increase in compressor pressure ratio due to the lower energy content of biomass-derived gas vis-à-vis natural gas, resulting in a larger gas mass flow.

The expected control strategy for the short-term is gas turbine rating due to its simplicity [3][5]. De-rating consists of imposing a lower gas turbine burning temperature and thus, lowering the compressor pressure ratio. Cofiring the biomass-derived gas with natural gas would increase the heating content of the resulting fuel reducing the impact of de-rating or even completely avoiding it. Furthermore, mixing would be desirable to avoid significant burner modifications, to increase combustion stability and, eventually, to reduce the risk of back stream flame propagation.

The cofiring proposal analyzed in this paper is backed by increasing availability of natural gas and sugar-cane residues in the State of São Paulo, Southeast of Brazil. Sugar-cane trash (leaves and tops of sugar-cane plant) is the biomass considered in this paper. Trash availability should grow fast in coming years due to the reduction of pre-burned harvesting in that region, while a newly built natural gas pipeline with capacity to supply 30 million Nm^3 per day crosses main sugar-cane areas. The end of the practice of burning sugar-cane leaves and tops might lead to a biomass yearly availability between 100- 200 PJ.

2. Cofiring experience and previous work

The term cofiring has been applied to designated combined use of biomass and fossil fuel, in power plants as well as in industrial steam boilers. The most accepted idea is burning a mix of biomass and coal in power plants that should be adapted to this purpose at the moment the useful life of the existing boilers expires. Owning to the substantial reduction on technical and economic risk, cofiring has been considered in some countries the first step for the enhancement of biomass use in power generation [6]. In USA, for instance, some coal burning electric utilities are becoming interested in biomass cofiring as a low-cost option for reducing greenhouse gas emissions. Cofiring provides a cost-effective way of utilizing biomass by taking advantage of the relatively high efficiency of large coal boilers without incurring a large investment [7].

Considering cofiring in gas turbines no similar experience is known. Co-combustion of LCV fuels and natural gas has been commercially implemented in power plants for the steel industry in Italy. Stambler [8] and Thoraval [9] report that the major steel maker in Italy – Ilva – has replaced old steam turbo-generators by a new combined cycle installation nominally rated 530 MW_e. The power plant has three similar units based on the GE MS9001/E gas turbine. The system has improved overall plant efficiency from 36 to 45 per cent. The combined cycle runs on a mixture of three different sources of waste gases from the steel mill: blast furnace gases with a low heating value (LHV) of 3.35 MJ/Nm^3, coke oven gas (LHV=18.84 MJ/Nm^3) and LD gases (LHV=8.7 Nm^3). The blast furnace gases provide the largest volume and the coke oven gases the lowest. The mixture with natural gas increases the LHV to values in between 6.3 and 8.4 MJ/Nm^3. The lower heating value in that range ensures that minimal thermal requirement for the combustion chamber design of the gas turbine and for flame stability is achieved. This plant has achieved more than 60,000 operating hours by March 1999. Another similar installation was planned to be installed in the process of repowering in Livorno, Italy (189 MW_e), expected to have become operational by third quarter of 2000.

No similar experience was found in open literature for biomass-derived gases. A report on cofiring has been produced in The Netherlands [10]. The work focused on the possibility and potential of cofiring LCV fuels and natural gas over different power configurations. Gas turbine constraints and required adaptations have been inventoried with the gas turbine suppliers at that country, i.e., General Electric, Asea Brown Boveri, Allison and Rolls Royce. Likewise, a similar study was developed some years ago at the National Renewable Energy Laboratory - NREL, USA, but just a preliminary analysis of technical options was conducted at that time [11].

3. Gas turbine hardware adaptation

3.1 Constraints and required modifications for using LCV fuels

Besides reducing the need of control strategies for gas turbines, the mixture with natural gas could minimize hardware modifications required for the use of LCV fuels in machines that have been designed for natural gas. The extent of hardware modifications depends on the heating value of syngas and on the type of gas turbine.

Combustion stability could be a matter of concern due to the LCV of the syngas, but major problems could be verified during the start-up when flame stability and ignition would be more difficult due to lower temperature [8]. The combustion stability for biomass-derived gas has been verified for the modified LM2500 combustor [12].

Using a LCV fuel gas pressure loss is increased due to the injection of a larger volume through a nozzle that has been designed for a fuel with much higher energy content. The replacement of the gas turbine nozzle might be necessary and, eventually, the replacement of the whole combustion chamber is required. According to Consonni and Larson [3] can-type combustors used in many industrial gas turbines generally provide adequate cross section and volume for complete and stable combustion with acceptable pressure drops. In fact, many industrial gas turbines have successfully operated for years using LCV fuels from, for instance, steel mills (e.g., blast-furnace gases). However, in accordance with De Kant [10], replacing the combustion chamber is said to be a necessary modification to adapt industrial GE gas turbines originally designed to burn natural gas. The same author estimates that this modification would increase the gas turbine cost in about 20 per cent. Neilson [12] describes modifications introduced in the aero-derivative GE-LM2500 for the operation with biomass-derived gas that include the combustion chamber with a new fuel nozzle, a new swirler venturi and a larger cowl opening. The fuel pipeline and manifolds also had to be adapted.

Another concern is the hydrogen content of the biomass-derived gases (between 10-20 per cent vol.) that is much higher than for natural gas. While this content is beneficial from the point of view of flame stability [3], it might lead to back stream flame propagation in a dry low NO_x combustion chamber [10]. The adiabatic flame temperature and theoretical air are also relevant parameters for the fuel switch, mainly due to thermal NO_x emissions concerns.

3.2. Reducing gas turbine modifications with cofiring

Table 1 presents the estimated composition for the derived gas from sugar-cane trash and for the natural gas considered in this paper. The biomass-derived gas composition was taken from

Walter *et al* [11]. The fuel mix LHV presented in Figure 1 was calculated based on these compositions.

Table 1. Composition of the biomass-derived gas and natural gas (% volume)

Component	Clean syngas	Gas natural
H_2	16.69	1.00
CO	19.98	-----
CO_2	10.49	0.52
CH_4	2.63	80.61
C_2H_2	-----	6.00
C_2H_4	-----	6.00
C_2H_6	-----	4.00
C_6H_6	0.33	-----
H_2O	3.24	0.07
N_2	46.64	1.80

Considering cofiring, the fuel mixture with natural gas increases the energy density and, hence, reduces the need for hardware modifications. According to De Kant [10], for shares of natural gas higher than 75 per cent (energy basis), or about 18 MJ/Nm^3 (see Figure 1), there would be no need for replacing the combustion chamber of industrial gas turbines manufactured by General Electric. At the same report it is informed that ABB has a special combustion system for gases with heating value between 8 and 16 MJ/Nm^3, such as those derived from coal gasification. This LHV range lies between 30 and 70 per cent of natural gas (energy basis) in the fuel mixture with biomass-derived gas, as can be seen in Figure 1.

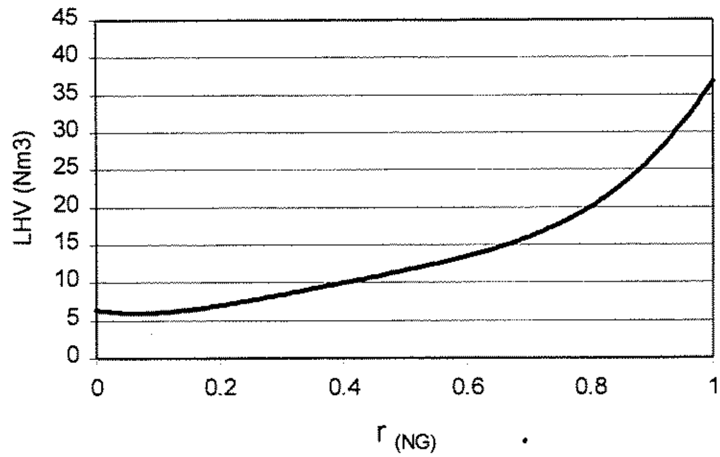

Figure 1. Estimated LHV as function of natural gas share in the fuel mix – $r_{(NG)}$ (energy basis)

Further tests are necessary before final recommendations on the suitability of biomass-derived gases for the industrial fuel injection systems can be obtained. However, primary indications are that cofiring has the potential to reduce the need for modifications in the combustion system or, at least, increase the heating content of the fuel mix to heating values such as those of gases derived from coal gasification. The use of medium LHV gases is commercially proven, so that adapted equipment is available.

3.3 Flame temperature and NOx formation

When biomass gas is mixed with natural gas the fuel flame temperature increases and, consequently, the formation of thermal NO_x. In gas turbines thermal NO_x is a major concern for natural gas combustion and its formation increases exponentially with the flame temperature [4]. Exclusively for biomass-derived gases, thermal NO_x formation is likely to be very low due to the lower flame temperature [3][14].

Variations of flame temperature as function of fuel mix composition are here represented by the adiabatic flame temperature (AFT) at stoichiometric conditions. Adiabatic flame temperature is the maximum value that could be achieved when combustion occurs adiabaticaly without involving work or variations on kinetic and potential energy. Figure 2 presents AFT variation as function of natural gas share in the fuel mixture. As it can be seen, the AFT for biomass-derived gas is about 20 per cent lower than for natural gas (1700 x 2100°C).

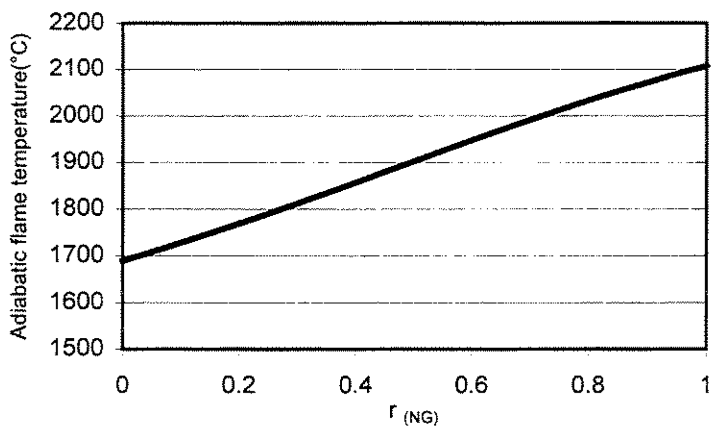

Figure 2. AFT as function of the natural gas share in the fuel mixture – $r_{(NG)}$ (energy basis)

The actual flame temperature will also depend on the degree of gas dissociation and on combustion excess air. Dissociation was not considered here. Flame temperature is theoretically a maximum at stoichiometric conditions and will fall off at both rich and lean mixtures. Results show that the excess air for simulated gas turbines operating at full load with natural gas varies between 270-300 per cent. It is estimated that for biomass-derived gas burning in de-rated gas turbines the combustion occurs with a 250-270 per cent excess air. Due to the composition of syngas and to the degree of de-rating that is imposed to the gas turbine, excess air do not varies linearly with the composition of fuel gas mix. For the simulation results obtained in this work, the excess air is between 210-215 per cent for a fuel mix with 50 per cent of natural (energy basis), which is considerably less than that for the case with 100 per cent natural gas. This tendency will have an impact on the actual fame temperature and, consequently, on the formation of thermal NO_x. As an illustration, Figure 3 presents the estimated stoichiometric air/fuel ratio as function of the fuel mixture.

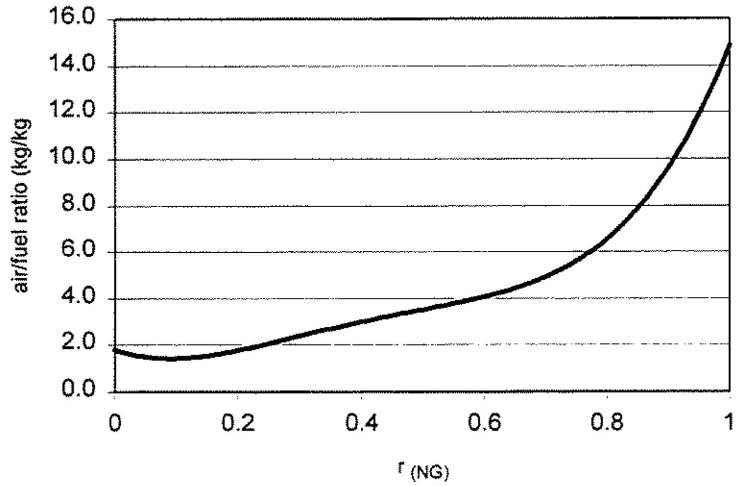

Figure 3. Stoichiometric air/fuel ratio as function of the natural gas share in the fuel mixture (energy basis)

Further studies and tests concerning NO_x emissions for cofiring are necessary, especially considering limitations for the use of dry-low combustion chambers, point which is associated with the hydrogen content of the fuel and is discussed below.

3.4 Hydrogen content

The hydrogen content in biomass-derived gas can be either desirable to improve the flame stability of the fuel-mix combustion or a drawback limiting the use of biomass-derived gas in dry low NO_x combustion chambers. Results carried out by General Electric suggest that the higher the hydrogen content, the lower the heating value required for stable combustion [3]. This is explained by the fact that hydrogen has a higher flame propagation speed than CO or CH_4, the main other combustible gases in biomass-derived gases.

The content of hydrogen is also associated with the possibility of back stream flame propagation in dry-low NO_x combustion that consists of pre-mixing fuel and air prior to the combustion. While General Electric specifications recommends no hydrogen in the fuel for some of its dry-low NO_x combustion systems, ABB sets a maximum of 5 per cent for the hydrogen content for its dry-low NO_x systems [10]. Cofiring could play a role in limiting the hydrogen content of the mixture, as natural gas contains low levels of hydrogen. However, as can be seen in Figure 4 the 5 per cent maximum content suggested by ABB will only be achieved for fuel mixtures with more than 90 per cent of natural gas (energy basis).

Further research and testing on this issue is still necessary until more reliable limits – and eventually less restrict – are established. In addition, manufactures might consider redesigning their dry-low NO_x systems in order to suit the biomass-derived gas. However, that is unlikely to occur in the short term and so other options, such as steam injection for NO_x emissions control, should be considered.

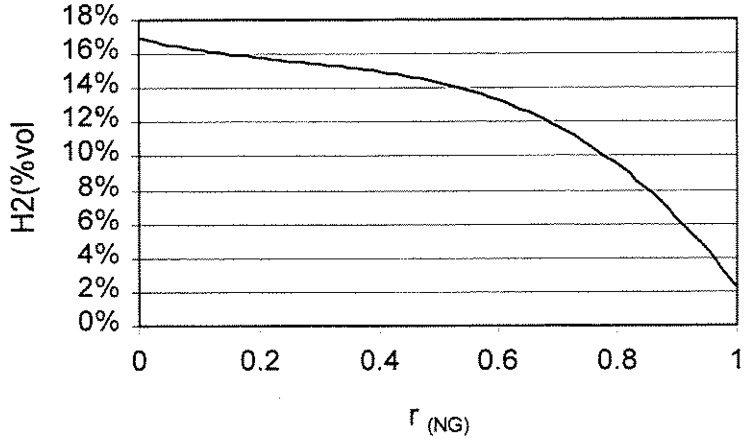

Figure 4. Hydrogen content as function of the natural gas share in the fuel mix (energy basis)

4. Power system description

The cofiring option analyzed in this paper is based on a combined cycle fueled by a mixture of natural gas and gas derived from biomass (sugar-cane trash) gasification. The capacity of the biomass gasifier and the size of the gas-cleaning module depend on the share of syngas in the gas mixture. Evaluating different capacities on power production, three combined cycles based on aero-derivative and on industrial gas turbines were considered. It is considered that the biomass gasification occurs in an atmospheric air-blown gasifier similar to those developed by the Swedish company TPS (Thermiska Processor AB). This type of gasifier is technically proven and likely to reach a commercial status on the short-term [2][15]. Gasification occurs with air injection in a circulating fluidized bed (CFB) at 2 bar. The primary step of gasification is followed by a second CFB reactor in which dolomite is used to catalyze the cracking of tars to gases and lower molecular weight vapors [15].

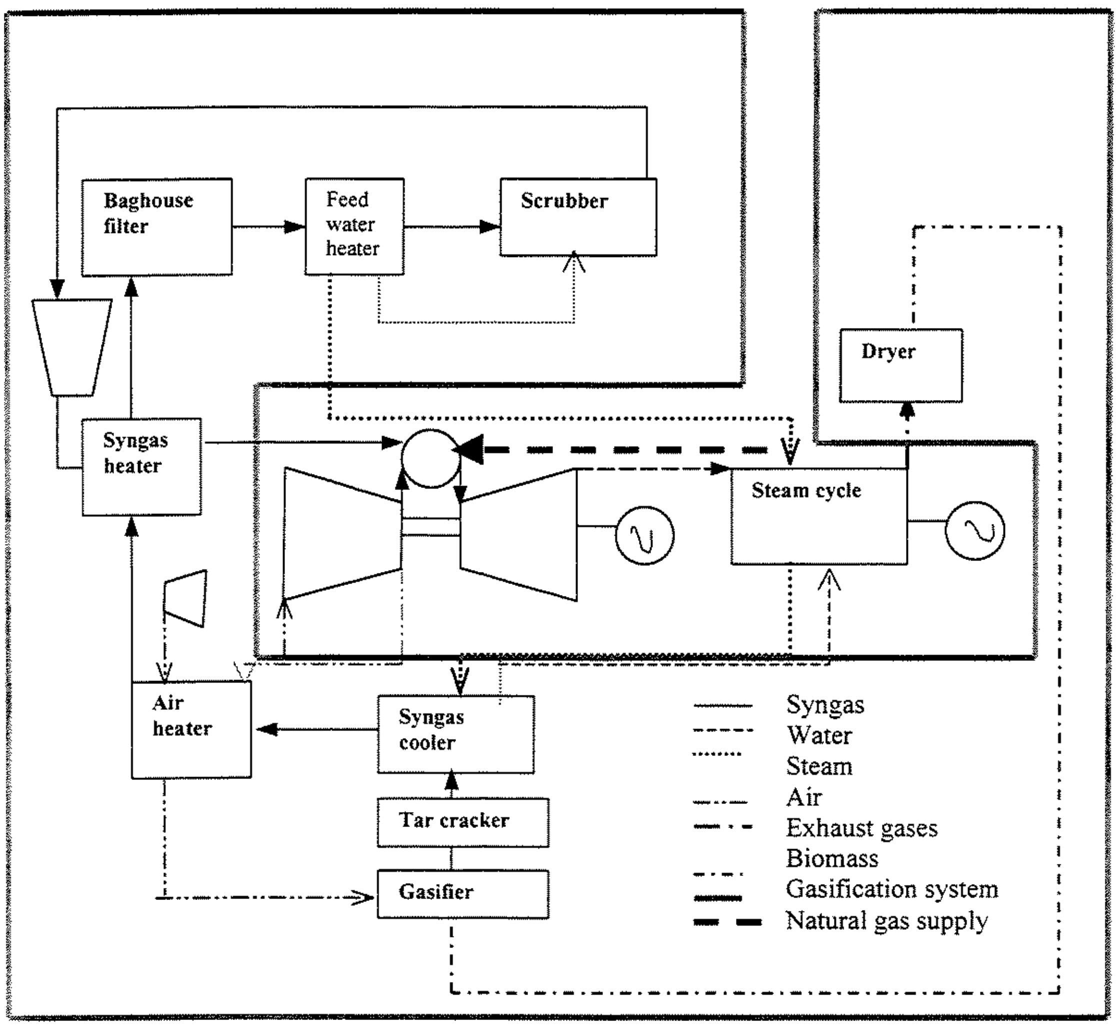

Figure 5. Scheme of the co-fired combined cycle considered

After the tar cracker, the raw gas is cooled and the heat is sequentially recovered to increase steam generation, to preheat the blast air, the syngas itself (before it enters the gas turbine) and to preheat the feed water for the heat recovery steam generator (HRSG). After the cooling, a bag house filter removes the particulates while remaining components are removed in a wet scrubber. Following the scrubber, the biomass gas is compressed and preheated to be injected in a gas turbine at 370°C. The energy of the exhaust gases are recovered at an unfired HRSG. It is designed that the biomass is dried by using flue gas from HRSG (down to 15 per cent moisture content). It is predicted that drying design conditions requires 200°C for the flue gas from the HRSG. Figure 5 represents a schematic drawing of the cycle.

Some characteristics of commercial gas turbines (GE LM2500, GE PG6101(FA) and GE PG7001) have been used for cycle modeling. The LM2500 model considered in this paper is, in fact, the aero-derivative machine modified by General Electric for the use of the biomass-derived gas [12]. The other two machines are heavy industrial gas turbines. Parameters that are not available at open literature have been estimated based on reference performance data for such machines. Combined cycles based on such machines are identified as aero-derivative (LM2500), medium size (PG6101) and large size (PG7001). These three gas turbine models were chosen in other to cover a broad range of power capacities. Simulation results presented in this paper were further used in feasibility studies based on scale effects [16].

5. Modeling assumptions

In BIG-CC or co-fired cycles, due to the lower heating value of the biomass-derived gas a larger mass flow goes trough the gas turbine expander. The only way this higher mass flow can be accommodate without any design change or gas turbine de-rating is the increase on compressor pressure ratio. The main problem associated with the increase in pressure ratio is that the compressor operation could approach its surge limit [4]. Off-design operation with increased compressor pressure ratio is also very aggressive to the gas turbine due to increased thermal and mechanical loads [17].

In order to keep a safe margin from the compressor surge limit control strategies should be applied to the gas turbine. Such control strategies include compressor blast-off, gas turbine de-rating and redesign of the inlet expander nozzle. The impact of these control strategies over the performance of BIG-CC plants were previously analyzed [18]. De-rating is the simplest approach that allows the use of biomass-derived gases in gas turbines that have been designed for natural gas, but it is also the worst option from the point of view of the cycle performance. As far as gas turbine is de-rated by means of the reduction of its maximum temperature the compressor pressure ratio can be reduced to acceptable values.

Performance evaluation of co-fired combined cycles requires an off-design procedure for gas turbine simulation. The main difficulty in predicting off-design performance of gas turbines comes from the fact that actual compressor maps are not available in open literature. Consequently, it is not easy to accurately predict variations of inlet airflow as function of pressure ratio variations, as well as to define surge margin. Simulation results presented in this paper are based on a computer model previously described by Walter *et al* [5] and by Souza *et al* [18]. Modeling simplifications lead to simulation results that cannot be associated to specific commercial gas turbines, but resemble classes of machines regarding their capacities.

According to the procedure a generic compressor map is assumed for the calculations. Surge limit is then estimated considering that the gas turbine operation with natural gas at ISO basis corresponds to a given compressor surge margin. The operation with natural gas was determined to be corresponding to a compressor map variable – CMV equal to 0.75. A CMV is defined as $(PR-1)/(PR_s-1)$, where PR is the pressure ratio at a given point and PR_s the pressure ratio that corresponds to surge at a given running line. Thus, CMV equal to 0.75 means that the compressor pressure ratio is relatively far from the surge line. It was also assumed that the limit for continuous operation of industrial gas turbines corresponds to a CMV = 0.95. In fact, the compressor characteristic of industrial gas turbines can cope with a large increase on the pressure ratio [10].

On the other hand, aero-derivative engines have a more critical compressor operation and control. These machines are double shaft and can go through changes on the rotational speed of the gas generator. Due to the broader range of compressor operation stricter control is need. The maximum pressure ratio for the aero derivative gas turbine was assumed to be the same as that proposed by Consonni and Larson [19], which corresponds to a CMV of 0.85.

An additional modeling simplification is that for all three simulated combined cycles it is assumed that steam is raised at just one pressure level in an unfired HRSG. The reason for this simplification is that for BIG-CC cycles the gains with multiple pressure configurations and reheating are only marginal due to the minimum exhaust gases temperature required for the dryer [19]. In this sense, the proposed configurations are not optimized for natural gas-fired combined cycles and simulation results of net plant efficiency are lower than performance figures listed in the literature [20]. A combined cycle based on one LM2500 operates with two pressure levels and heat recovery steam generators of combined cycles based on Frame 6 and Frame 7 gas turbines comprise three pressure levels and reheat.

In these conditions, for instance, a commercial cycle based on one Frame 7 can reach net efficiency of about 56 per cent (ISO basis) [20] while simulation result is 49 per cent. Most of this difference is due to the simplification of just one steam pressure level. A second main reason is the own level of steam pressure, that do not necessarily leads to the optimization of the simplified combined cycle. However, model simplifications do not invalidate the main conclusions of this work. Steam pressure was chosen as 8.8 MPa for the combined cycle based on aero-derivative gas turbine and as 10 MPa for the other two cycles. The isentropic efficiency of the steam turbine is set constant and equal to 75 per cent in all simulated cases. Part of the steam flow is extracted at 1.8 MPa for the deaerator. The remaining steam is expanded in the low-pressure stage and condensed at 9.6 kPa.

Gas turbine de-rating leads to the reduction of steam temperature. Modeling imposes that superheated steam temperature is lowered to keep the minimum HRSG approach of 30°C. Steam temperature is increased with cofiring up to the design point. In fact, maximum steam temperatures are reached for shares of natural gas as low as 20 per cent (energy basis). According to the fuel mixture steam production is constrained to keep the required minimum HRSG exhaust temperature (200°C) to satisfy dryer operation. Varying the share of syngas in the fuel mix also provokes penalties on the operation of the HRSG feed-water heater. For the case when only biomass-derived gas is used, feed-water is heated to 120°C. This temperature is reduced when the share of biomass-derived gas in the fuel mix is decreased. The main assumptions for the modeling of the combined cycles are listed in Table 2.

Table 2. Main assumptions adopted for calculations

HRSG & steam cycle	• Approach $\Delta T = 30°C$; pinch point $\Delta T = 15°C$. • Heat losses 0.7% of heat released by gas; pressure drop at the gas side 3kPa, pressure drop at the superheater 10%. • Overall isentropic efficiency of steam turbine 0.75. • Steam pressure at the condenser 9.6 kPa. • Water outflow from deaerator: 488 kPa, 120°C. • Total auxiliary power = 160% of the estimated power for the pumps (isentropic efficiency 0.65). • Cycle based on aero-derivative GTs: Steam raise at 8 MPa, 480°C (maximum T). • Medium and large cycles: Steam raised at 10 MPa, 538°C (maximum T).
Gasifier	• Outlet syngas temperature 870°C, outlet pressure 0.20 MPa, $\Delta p=0.02MPa$
Dryer	• Biomass dried from 50% to 15% mc, exiting at 70°C
Heat exchangers	• $\Delta p/p$ 2%; heat losses equivalent to 2% of heat transferred
Syngas compressor	• Organic and electric efficiencies 90%.
Air compressor	• Polytropic efficiency 80%. • Organic and electric efficiency 90%.
Ambient air	15°C, p=0.1013 MPa; humidity 60%

6. Cofiring results for gas turbine de-rating

6.1 Imposed de-rating

Cofiring results are investigated over the whole range of fuel mixture. As previously mentioned, when just natural gas is considered results of power plant performance are lower vis-à-vis highly optimized plants available in the market for the same capacity. First set of results presented in this paper are based on de-rating as gas turbine control strategy for just biomass-derived gas burning. De-rating is gradually reduced as more natural is applied up to the point in which temperature reduction is no longer necessary.

Above a certain amount of natural gas in the fuel mix gas turbine de-rating is no longer necessary. For the aero-derivative gas turbine, as a more severe surge control is applied regarding industrial models, a higher share of natural gas in the fuel mix is necessary to offset de-rating. For the aero-derivative gas turbine the minimum share of natural gas in the fuel mix that allows compressor operation at the maximum pre-established pressure ratio 19.3 and maximum cycle temperature 1258°C is 54.2 per cent (energy basis). For the gas turbine identified as medium size the minimum share of natural gas that keeps compressor operation at 16.4 and maximum cycle temperature at 1288°C is 36.8 per cent. Approximately the same share of natural gas is estimated for the gas turbine identified as large size, but to keep pressure ratio as 16.2 and maximum cycle temperature as 1371°C.

6.2 Effects on cycle efficiency

Effects of cofiring over the overall cycle efficiency – as function of natural gas share in the fuel mix – are presented in Figures 6 (mass basis) and 7 (energy basis). As it was expected, there is a continuous increase on cycle efficiency by increasing the natural gas content in the fuel mix. Gains on efficiency are very sharp within the range of fuel mix that corresponds to de-rating necessity, i.e., up to 6-11 per cent of natural gas in mass basis or up to 37-54 per cent in energy basis.

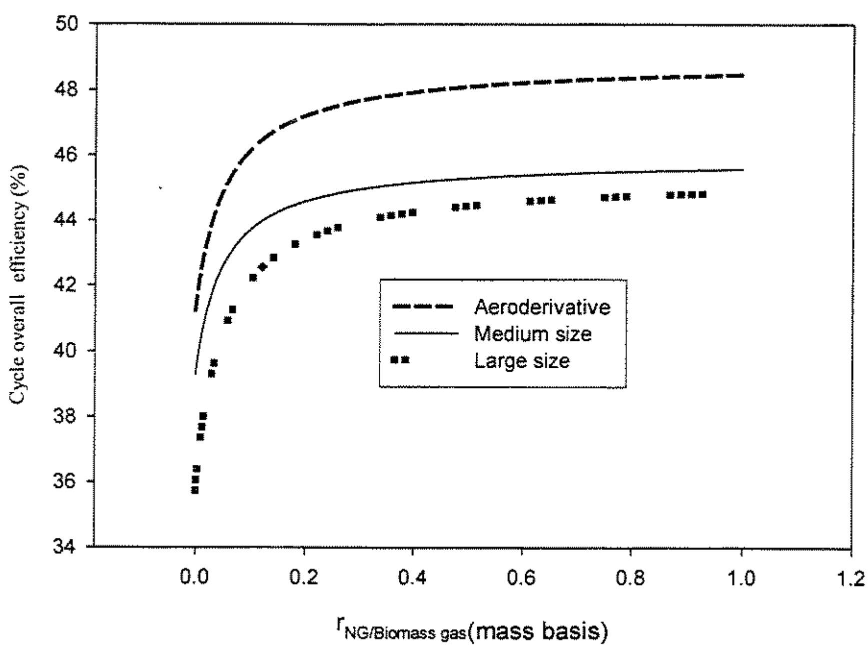

Figure 6. Estimated cycle efficiency as function of the natural gas share in the fuel mixture (mass basis)

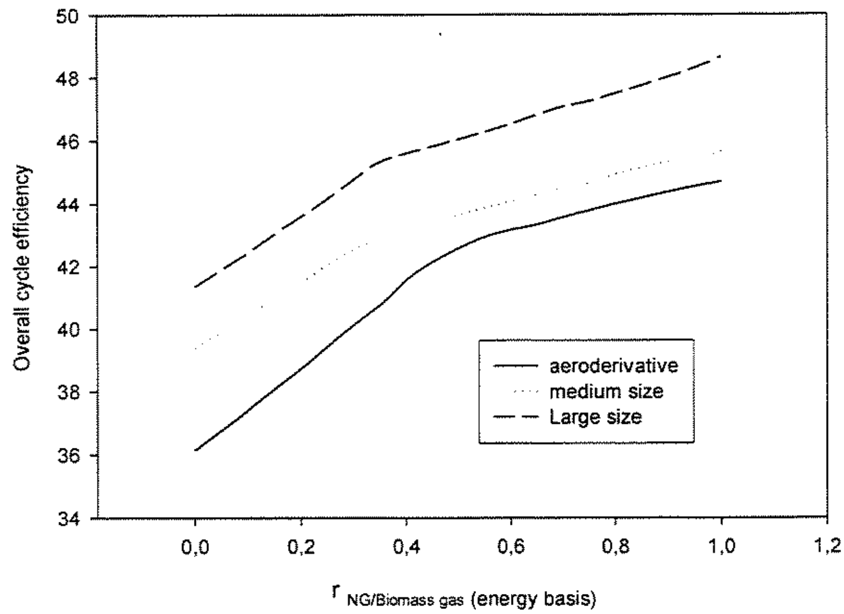

Figure 7. Estimated cycle efficiency as function of the natural gas share in the fuel mixture (energy basis)

When just biomass-derived gas is burned estimated cycle efficiency lies between 80-87 per cent from the value that would corresponds to full natural gas use. At the end of de-rating region cycle efficiency corresponds to 94-95 per cent of the maximum value (just natural gas burning). It is noticeable that after the de-rating region, the difference between the medium size cycle and the large one is getting larger (up to 7 per cent) as function of the higher temperature of latter. When only biomass-derived gas is used the efficiency of the larger power unit is just 5 per cent higher than the medium size plant. On the other hand, the efficiency of the cycle based on the aero-derivative gas turbine drops considerably in the de-rating region due to the more severe constraints imposed through the modeling.

6.3 Effects on output power

The output power is the sum of the gas turbine and steam power production, minus the cycle power requirements that include power consumption on syngas and air compressors. For BIG-CC systems based on atmospheric gasification, the consumption of syngas compressor represents a considerable loss on power. Considering the cases in which just biomass-derived gas is used, compressor power consumption represents between 15-18 per cent of the gross power produced by the cycles, being the cycle based on the aero-derivative machine the one with the highest share. For two of the three cycles studied the effects of the fuel mix over the power production for the gas turbine, the steam cycle and the overall output are presented in Figures 8-9. In addition, the same figures present the power consumed by the biomass gas compressor over. Results for the plant based on the medium size gas turbine are similar to those presented in Figure 9 as medium and large gas turbines have the same magnitude of de-rating.

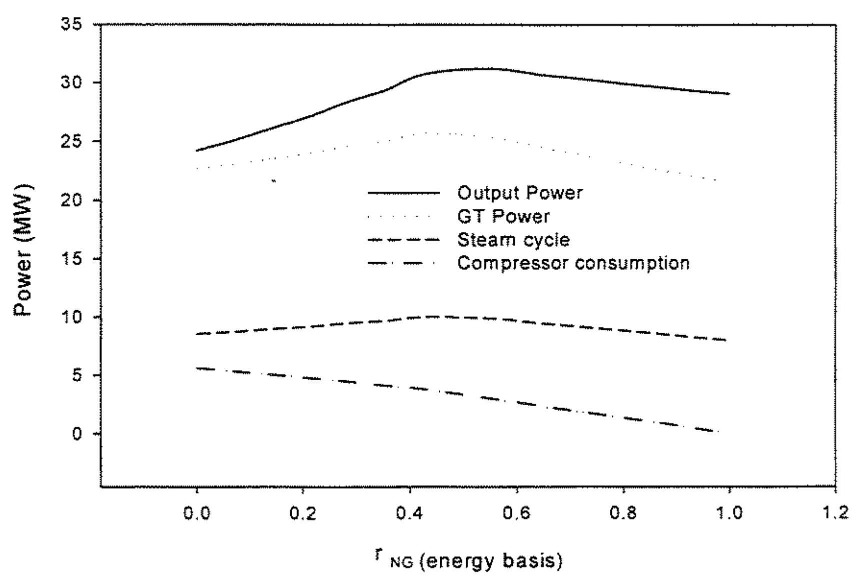

Figure 8. Effects of natural gas shares in the fuel mix over the power production for the cycle based on the aero-derivative gas turbine

The peak on gas turbine power production occurs just at the end of de-rating region, i.e., around 55 per cent of natural gas in the fuel mix (energy basis) for the aero-derivative and between to 35-37 per cent for the industrial gas turbines. Gas turbine power rises as de-rating is reduced, reaching its peak when surge control is no longer needed. In comparison to the natural gas case, gas turbines can produce more power when biomass-derived gas is used due to the larger mass flow. However, due to the de-rating penalties, gas turbine output power is only slightly larger for the biomass-derived gas case. As shown by Souza *et al* [18], gas turbine power production would be considerably larger in case other control strategies were applied rather than de-rating.

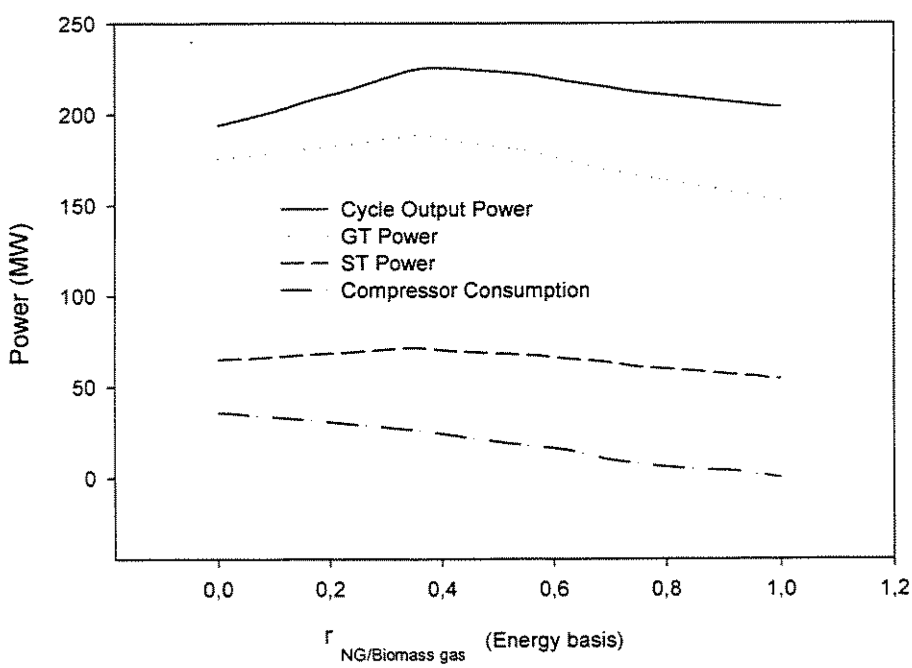

Figure 9. Effects of natural gas shares in the fuel mix over the power production for the cycle based on the aero-derivative gas turbine

Power production by the bottoming steam cycle is also affected by gas turbine de-rating with its maximum being by the end of de-rating region as well. In case no de-rating would be applied, the more biomass-derived gas is used the larger is the mass flow of gas turbine exhaust gases. However, when de-rating is imposed the temperature of the exhaust gases is reduced, reducing steam production rates. Furthermore, steam temperature also needs to be reduced to keep the minimum approach temperature. Simulation results indicate that the drop in steam temperature can be avoided for low shares of natural gas that is around 20-27 per cent in energy basis.

Overall output power has a similar profile with its maximum value occurring by the end of de-rating region. Comparing to the case of full biomass-derived gas burning gains on power are over 30 per cent for the aero-derivative-based cycles and about 15 per cent for the industrial gas turbine-based cycle. However, as can be seen in Figures 8 and 9 the use of higher shares of biomass-derived gas considerably affects overall power plant. The reason is the larger the share of biomass-derived gas larger is the auxiliary power consumption for syngas production and, more importantly, the requirements of the syngas compressor.

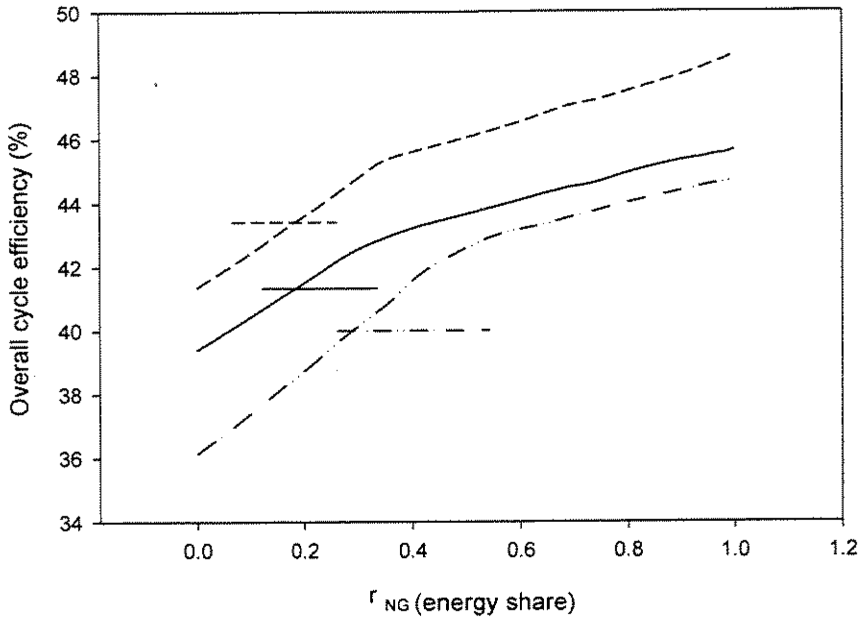

Figure 10. Net plant efficiency of BIG-CC units based on retrofitted gas turbines and co-fired schemes

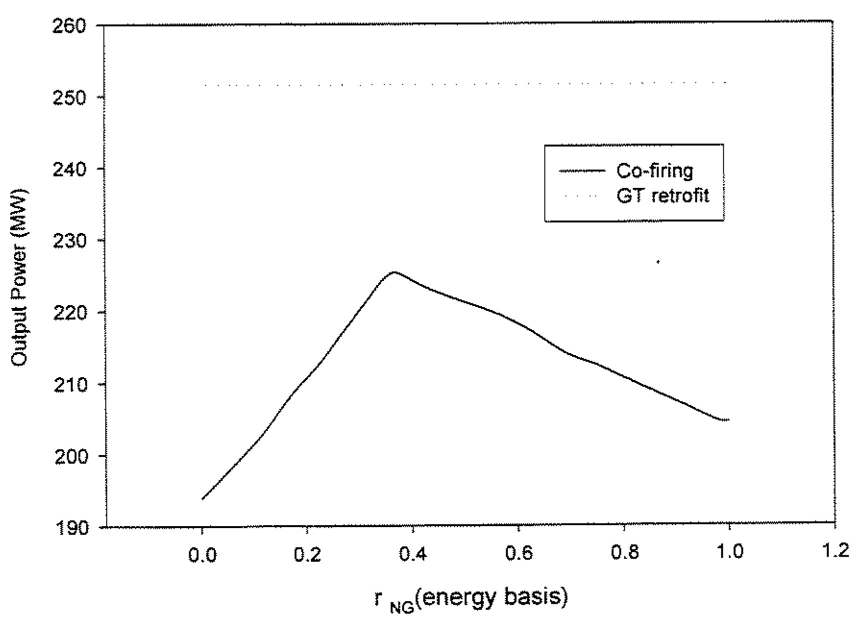

Figure 11. Net power production of BIG-CC units based on retrofitted gas turbines and co-fired schemes

7. Cofiring results for gas turbine retrofit

Cofiring is proposed by the authors as a way to reduce the drawbacks of using a fuel with low heating value in gas turbines originally designed for natural gas. The complete redesign of gas turbines might be a long-term option as the market for BIG-GT cycles gets developed. The complete redesign would include a new combustion chamber and new expander inlet nozzles. The increase in the expander area would allow a larger mass flow to go through the gas turbine without the dangerous increase on compressor pressure ratio. Conceptually, the change is similar to that performed in steam injection gas turbines – STIG that should cope with increased mass flow. The mass flow augmentation for STIG gas turbines are yet small when compared to the large mass flow increase that is necessary when biomass is used.

A brief comparison from a performance point of view between co-fired schemes and BIG-CC cycles based on equivalent but retrofitted gas turbines is presented bellow. The augmentation in the expander inlet area would allow the gas turbine to run at the same compressor pressure ratio as when natural gas is used without gas turbine de-rating.

Figure 10 represents the comparison for the cycle efficiency of the three power plants considered. Figure 10 is similar to Figure 4 with the introduction of horizontal marks that indicate cycle efficiency of equivalent BIG-CC units based on retrofitted gas turbines. It should be noticed that the efficiency levels that could be attained with retrofitted gas turbines can be easily overcome by co-fired schemes with low shares of natural gas, such as 15-20 per cent in energy basis.

However, the main gain that can be reached with gas turbine retrofitting is on output power. It is estimated that the increase in the expander inlet area allows the power cycle to produce 12 per cent more power than the maximum value achieved for co-fired schemes. Figure 11 presents the comparison between the co-fired power plant based on the large size gas turbine and a BIG-CC unit based on the retrofitted large size gas turbine. The upper line in Figure 11 corresponds to the output net power of a BIG-CC unit based on a redesigned gas turbine burning only biomass-derived gas.

8. Conclusions

Cofiring is a promising option to deal with technological drawbacks of using biomass-derived gas in gas turbines. Cofiring increases the heating value of the fuel leading to fewer adaptations of the gas turbines for the use of biomass-derived gas and to no need for a control strategy to limit the pressure increase. The avoidance of a control strategy is particularly beneficial as far as de-rating has been considered. Within assumptions considered for this work, it is estimated that cofiring can avoid de-rating for shares of natural gas between 35-50 per cent (energy basis). Vis-à-vis the exclusively use of biomass-derived gas important gains in power production could be obtained around those shares. Thermal efficiency gets very close – about 95 per cent – of the level achieved when just natural gas is used.

With cofiring the output power peak occurs by the end of gas turbine de-rating region where the machine simultaneously achieves its maximum temperature, i.e. no de-rating is necessary, and its maximum compressor pressure ratio. The larger mass flow of gases in comparison to the case with just natural gas burning also contributes with the power peak.

Cofiring could also avoid dramatic modifications in gas turbines, like the replacement of the combustion chamber and, eventually, allowing the use of biomass-derived gases at some extent in dry low NO_x systems. However, non conclusive results show that it would be possible only at very high shares of natural gas, that are estimated higher than 90 per cent in energy basis. Further studies have to be carried out regarding this subject. It is also forecasted that co-firing could also improve flame stability.

Considering a long-term scenario, cofiring was also compared with BIG-CC cycles based on redesigned gas turbines exclusively using biomass-derived gas. Regarding power plant efficiency modeling results show that cofiring could be a better option for shares of natural gas in the fuel mix as low as 15-20 per cent in energy basis. However, retrofitting of gas turbines would be a better long term option regarding power production as it is estimated that the output power could be about 10 per cent higher in comparison to the peak of co-fired systems.

Results here presented were obtained from a simulation procedure based on some simplifications. Results reflect generic characteristics of gas turbines and are not based on specific engines. In this sense, assumptions done and the results achieved are quite reasonable. Furthermore, configurations proposed for the combined cycles are not optimized for fuel mixtures richer in natural gas. Consequently, optimal points from a performance point of view could require even less natural gas in the fuel mix. Additionally, cofiring option makes more sense for gas turbines that cannot cope with the increased pressure ratios associated with the use of LCV fuels. Finally, cost-effectiveness evaluation is mandatory to complete the assessment of the cofiring option and should be further performed.

Acknowledgements

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Capítulo 5

Análise Técnico-Econômica de Sistemas de Gaseificação de Biomassa Integrada a Ciclos Combinados "Cofired", com Inclusão de Economias de Escala

Síntese

O presente capítulo é apresentado na forma de um artigo ("Techno-economic analysis of co-fired biomass integrated gasification/combined cycle systems with inclusion of economies of scale") submetido à publicação na revista Energy: The International Journal. Os resultados apresentados no artigo foram obtidos durante o desenvolvimento desta tese.

Os resultados apresentados neste capítulo complementam aqueles apresentados no capítulo anterior, e que correspondem aos resultados da simulação computacional dos sistemas BIG-CC cofiring. O trabalho feito buscou identificar como a opção cofiring pode contribuir para a melhoria de competitividade da produção de eletricidade em sistemas BIG-CC. Em adição às vantagens de maior eficiência na geração elétrica, identificadas no capítulo anterior, demonstra-se neste capítulo os benefícios das economias de escala. O trabalho integrou resultados da simulação computacional com programação linear, de forma a ampliar o escopo da análise do ponto de vista dos custos e das diferentes opções de capacidade. A análise econômica diz respeito à primeira geração da tecnologia BIG-CC.

Estima-se que o "*de-rating*" de turbinas a gás pode implicar elevação de até 8 US$/MWh nos custos da eletricidade gerada em sistemas BIG-CC. Com o cofiring, o "*de-rating*" pode ser evitado. Ademais, o cofiring permite que as plantas de potência sejam aumentadas em capacidade em relação aos sistemas que operam exclusivamente com biomassa. A restrição imposta deve-se ao porte máximo dos gaseificadores de biomassa (cerca de 2000 t/dia de biomassa seca, para cada unidade, ou cerca de 350-450 MW_{th}). A faixa de potência considerada neste trabalho para os sistemas cofiring varia de 20 a 300 MW_e. Na medida em que aumenta-se a capacidade, aumentam os custos de transporte e de armazenamento da biomassa. Conclui-se, no entanto, que os ganhos alcançados com as economias de escala superam os custos adicionais de logística.

Demonstra-se que devido aos efeitos de escala dos equipamentos de gaseificação e de limpeza dos gases, a parcela da eletricidade gerada por biomassa alcança um custo mínimo quando a fração de gás natural na mistura combustível está por volta de 50%. De acordo com os resultados, uma planta com capacidade total de 300 MW_e é a que apresenta menores custos, sendo que metade da capacidade corresponde ao aporte da biomassa. No curto prazo, e para as condições Brasileiras, o custo da eletricidade gerada a partir da biomassa é estimado em 59 US$/MWh. No médio-longo prazos esse custo pode cair para cerca de 42 US$/MWh, o que faria com a opção fosse competitiva em relação às demais alternativas de expansão da capacidade de geração elétrica.

Uma análise de sensibilidade foi feita para uma planta BIG-CC cofired, de 100 MW_e de capacidade total. Os resultados mostram que a viabilidade econômica é mais afetada pela eficiência e pelos custos de capital do sistema.

Techno-economic analysis of co-fired biomass Integrated gasification / combined cycle systems with inclusion of economies of scale

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ABSTRACT: This work investigates how co-firing of natural gas fired combined cycles can improve the cost-effectiveness of power generation from biomass via BIG/CC-technology. The key advantages of co-firing are better efficiencies and lower costs through economies of scale. This study integrated performance modelling results from co-fired CC's and linear programming approaches to make full costs analyses of a wide variety of co-firing modes and capacity ranges. This study focuses on the implementation of this technology on the short-term in the Brazilian context. Therefore, atmospheric directly heated gasification technology is the focus of attention in this work and cost analyses presented apply to first generation plants. The biomass resource considered is mainly trash, which is produced in large volumes at sugar cane cultivation and largely unutilised.

The analyses show that mixing with natural gas results in major improvements for the cost effectiveness of biomass based power generation via an integrated gasifier-gas turbine configuration, resulting from substantial efficiency gains and economies of scale. The increase in efficiency through co-firing avoids major efficiency losses if de-rated gas turbines were used for firing biomass produced LCV gas only. The impact of de-rating on the COE can be as high as US$8/MWh. Furthermore, co-firing allows combined cycles to be scaled up beyond the capacity limits imposed by single vessel gasifiers that may be realized up to a capacity of 2,000 dry tonnes per day input (or 350-450MWth). This work considered a scale range of 20-300 MWe. Increasing the scale of the biomass fired capacity also results in increasing costs for biomass transportation and storage. However, the analyses shows that the economies of scale of the conversion system clearly outweigh the costs of logistics in the Brazilian context.

The obtainable COE for the biomass shares in a co-fired scheme reach a minimum; the breakeven point lays at about 50% energy input for any of the capacities. Beyond 50% natural gas share, the COE start to rise (due to the smaller capacities of the biomass conversion equipment) and might eventually be higher than the very high COE for BIG-CC`s fired by biomass only. The most economically sound co-fired plant has a total capacity of 300MWe, of which 50% of the energy input comes from biomass produced fuel gas. With assumptions made (short term, Brazilian context), the COE for biomass reach a minimum of US$59/MWh. On somewhat longer term, biomass fuel supply costs reduction and natural gas price increases are likely and the COE may than be lowered to US$ 42/MWh, which is lower than the projected marginal cost of adding new generation capacity in the coming years. Sensitivity analysis show that for a share of 50% of the energy input from biomass for a 100MWe co-fired plant, the most sensitive parameter is the efficiency, followed by the capital costs of the combined cycle, the biomass gasification and gas cleaning equipment and the finally, biomass fuel costs.

Keywords: Co-firing combined cycles, cost of electricity from biomass, BIG/CC-technology.

1. INTRODUCTION AND RATIONALE

BIG/CC technology offers the promise of efficient, clean and cost effective power generation from biomass [1], [2]. Besides some initial technological drawbacks which are currently resolved in demonstration projects (e.g. reference to the ARBRE project in UK), the high costs of the first generation BIG/GC systems is a barrier for its implementation in the short-term [3]. However, co-firing combined cycles with fuel gas produced via gasification of biomass and natural gas may substantially reduce the costs of power generation from biomass due to increased efficiency and the economies of scale of larger combined cycles partly fired by natural gas [4]. Furthermore, such a system is flexible in its fuel supply and co-firing can compensate for technical problems that can occur when firing turbines with LCV gases (as also results from direct biomass gasification with air) instead of natural gas or kerosene for which those engines are generally optimised at present. Using LCV gases in commercially available turbines generally leads to sub-optimal operation and de-rating is required [5], [6]. The performance of the BIG-GT systems can be substantially improved with co-firing as the need of de-rating[1] the gas turbine is reduced or completely avoided depending on the share of natural gas in the mixture [7]. Besides the benefits associated to the flexibility in view of fuel prices fluctuations, the combined use of both fuels can significantly lower the costs of power generation from biomass. The cost reduction can be attained with a better performance and economies of scale. Many factors play a role in the techno-economic performance of co-fired combined cycles though; economies of scale, efficiency impacts and logistics of biomass and identifying optimal configuration is a complex matter.

The key objectives of this study are therefore to explore the techno-economic performance of co-fired schemes consisting of a combined cycles using varying mixtures of natural gas and fuel gas derived from biomass gasification. This analysis will include the wide capacity range of gas turbines currently available on the market. Furthermore, the logistics of the biomass supply, which become more complex and costly for larger scale systems, are explicitly included in the economic assessment, to investigate the trade-offs between obtaining economies of scale versus the costs of the biomass logistics.

Those analyses are carried out for the Brazilian context, more specifically the sugar industry in Sao Paulo State. São Paulo, where about 70% of the sugar cane production is located in Brazil, the country with the largest cane production in the world. The biomass fuel considered for this analysis is sugar cane trash, which consists of the tops and leaves of the sugar cane plant. Those residues are getting increasingly available in the state of Sao Paulo, because pre-burned cane harvesting is not allowed any more due to recent legislation in São Paulo. Eventually, this may lead to an increase of trash availability of around 200PJ per year [8]. At the same

[1] De-rating is the reduction of the GT maximum temperature to avoid the pressure ratio increase to unacceptable levels when

time, large amounts of natural gas are imported from Bolivia. In spite that this natural gas is planned to be largely used in various (heavy) industries, the use in combined cycles is mandatory on the shorter term to guarantee large scale demand in the early years of the take or pay[2] contract. This situation; substantial availability of low cost biomass resources combined with large scale supply of relatively cheap natural gas, make it even more relevant to consider the discussed co-firing schemes in this particular region of the world. Conditions to demonstrate co-firing may be excellent on short term and provide a basis for application of (co-fired) BIG/CC technology in other parts of the world.

This paper contains the following: description of the technology considered, description of a generic approach for the system calculations to determine their performance for the varying gas mixtures and capacities ranges considered. Part of this performance modelling is based on related work [5], [7] and extended further in this paper. The core of the work is a detailed economic analysis that includes logistics and co-firing scenarios over a wide capacity range for co-fired combined cycles. The work is finalised by sensitivity analyses, discussion and conclusions.

2. SYSTEM DESCRIPTION

In order to simulate the impacts on the efficiency of co-firing schemes, a generic model was developed. The model relates the amounts (and shares) of biomass derived gas and natural gas to the output power and the energy efficiency of the total co-fired BIG/CC system. It incorporates changes in efficiency, capacity and costs when the amounts of natural gas and biomass-derived gases are varied. In order to do so, the following aspects are dealt with: first, the BIG/CC technology considered in this study is described (section 2.1). Second, the modelling approach followed to make performance estimates of co-fired combined cycles, including de-rating strategies is explained (section 2.2). Third, in section 2.3, the procedure to

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a much larger volume of low calorific gases goes through the GT to achieve the same energy release as NG.

[2] In existing contracts with Bolivia, the buyer is required to either take the total volume under the transaction or pay for it accordingly, or pay the total cost for the amount of gas transacted for even if the gas was not really used.

translate the calculated results for concrete turbine types to a general model to simulate system performance in relation to it's capacity over a wide capacity range is described.

2.1 BIG/CC technology considered

The co-firing system is a combined cycle fuelled by both natural gas and fuel gas produced via gasification of biomass. Three types of combined cycles are evaluated in order to determine the performance for a wide capacity range (20-300MWe): one based on an aero derivative gas turbine and two cycles of different sizes using industrial gas turbines. With respect to the biomass gasification, this study focuses on nearly atmospheric air-blown CFB gasifier, similar to technology developed by TPS (Termiska processer AB) in Sweden [2]. This type of gasifier is chosen since it is technically proven and likely to reach a commercial status for BIG/CC applications on the short-term. For BIG/CC operation, biomass is dried to 15% moisture content by using flue gas from the HRSG. Drying design conditions require a temperature level of about 200°C for the flue gas. Gasification occurs with air injection in a circulating fluidised bed (CFB) fuel at 2 bar (1.47air/kg of dry biomass). A second CFB reactor follows the gasifier for cracking tars. This reactor operates at a slightly higher temperature and cracks the tars to lighter hydrocarbons. After the tar cracker, the raw gas is cooled and the heat is sequentially recovered to increase steam generation, to preheat the blast air, the fuel gas itself (before it enters the GT), and the feed water for the boiler. After the cooling, a baghouse filter removes the particulates. Remaining components are removed in a wet scrubber. After the scrubber, the biomass gas is compressed and preheated to be injected in the combustion chambers of the GT at 370 °C. Hot exhaust gases are led to a HRSG to produce steam that subsequently drives a steam turbine. The biomass feedstock is trash for which composition data are reported in [6]. Figure 1 depicts the BIG/CC process scheme.

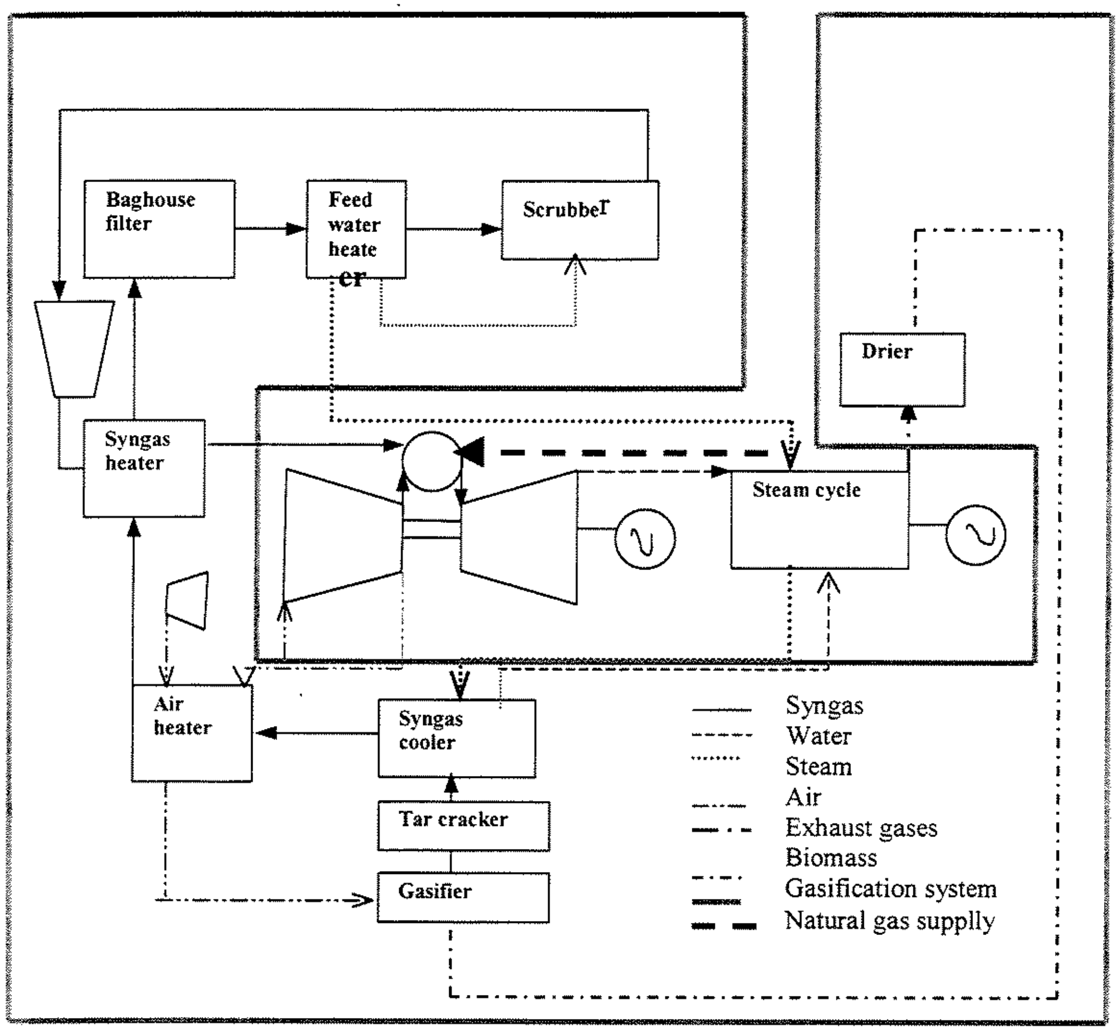

Figure 1. Scheme of the BIG/CC technology considered for this study; natural gas is explicitly taken up as fuel input; the modelling includes performance simulation of firing different turbine types with different gas mixtures.

2.2 Performance modelling of co-fired BIG/CC's

Commercially available combined cycles are optimised for the use of natural gas (or kerosene) and benefit from the high temperatures and multiple pressure configurations at large scales.

Combined cycles that are fully designed for the use of biomass derived low calorific gases (typically 5-7 MJ/Nm3 compared to about 42 MJ/Nm3 for natural gas) can only become available with the development of a market for BIG-GT. This market does not exist yet and for the short-term, re-designing is not a realistic option due to the high costs and available gas turbines should be adapted rather than re-designed for the use of biomass gas. The use of biomass derived LCV fuel gas in available gas turbines requires de-rating, which is the simplest strategy for the use of biomass gas in gas turbines designed for natural gas [6]. De-rating leads to considerable penalties for cycle performance and limits the gains in efficiency at larger capacities, as de-rating requires the combustion temperatures to be lowered. The need of de-rating gas turbines comes from the undesirable increase in pressure ratio when LCV gas is used. The higher-pressure ratios are necessary to accommodate a much larger mass flow of biomass gas[3] but are likely to lead to operation dangerously close to surge limits. Unless the manufacturer guarantees the turbine can cope with the increased pressure, de-rating is the strategy expected to be applied for the use of biomass gas in gas turbines for the short-term.

In addition to de-rating, another limiting factor for the efficiency increase of BIG-CC`s is the steam cycle configuration that is based on single pressure. While substantial gains are obtained with multiple pressure configurations for commercial Combined Cycles fired with natural gas, they would lead only to marginal gains for BIG-CC's[4] [1].

In the modelling a limit is imposed to the pressure ratio and the gas turbine is de-rated so that the operation is kept under this limit. Co-firing with natural gas can reduce the need of de-rating the gas turbine or even offset it, because the average heating value of the gas is proportionally increased. As the share of natural gas in the gas mixture that fires a gas turbine is increased for a fixed capacity, there are gains in efficiency that are related to the reduction of de-rating. The efficiency is also improved with the increase in capacity as the cycle temperatures get higher and the steam cycle gets more complex and efficient. The pace at which the efficiency increases with the capacity for biomass-derived gases and natural gas is

[3] the biomass gas mass flow that has to go through the gas turbine is about 9-10 times larger so that the same energy release as from natural gas is achieved.

[4] Because the HRSG exhaust temperature must remain around 200°C) for sufficient biomass drying

different, though. Those relations are simulated by using dedicated GT models. The basis for the model is composed of results for three different sizes of combined cycles that have been described in [6], [7].

The variation of cycle efficiency for each of the cycles for varying shares of natural gas (expressed as mass fraction) is presented in figure 2. De-rating is applied up to about 10% of natural gas for the combined cycle with an aero derivative gas turbine and to about 6% for the industrial gas turbines, showing a steep decline of efficiency below those percentages. Different margins from the surge line are set for the aero derivative and industrial gas turbines.[5] The reason is that compressor operation and control is more critical for aeroderivative engines than for industrial engines since on aeroderivative engines the compressor shaft is not connected to a generator, allowing it to rotate without control from the generator [9].

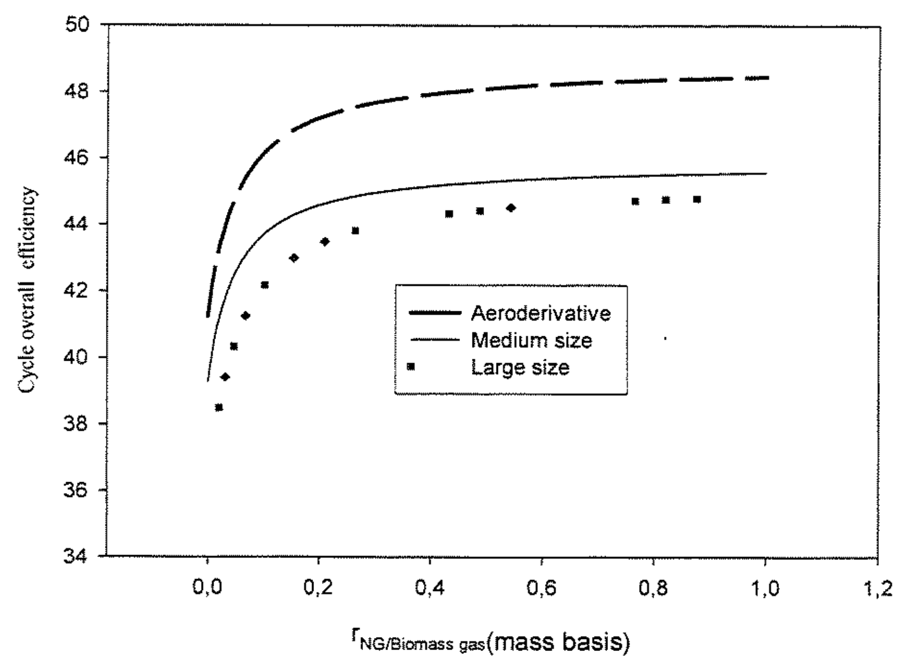

Figure 2. Efficiency variation over various shares of natural gas [7]

[5] The pressure ratios that are the limits set for the de-rating correspond to a CMV = 0.75 for the aeroderivative gas turbines and a CMV =0.95 for the industrial GT's

2.3 Translating performance of specific combined cycles to a generic relations for larger capacity ranges.

The efficiency of combined cycles varies considerably as manufacturers can offer many different configurations that depend on the trade-off between the capital investment, maintenance and efficiency. However, in general terms, the increase in capacity leads to an increase in efficiency as higher combustion temperatures are achieved. Also, more complex and efficient steam cycles configurations become feasible at larger scales[6]. A generic relation between the combined cycle efficiency and its' capacity can be derived from the data in Gas turbine world handbook [10]. This is presented in figure 3, showing that on average, a clear trend can be found between efficiency and scale; a low squared-R coefficient (0.6) was obtained to derive a generic trend line to describe this relation.

In order to describe a generic model for the combined cycle efficiency in relation to scale as well as heating value of the fuel gas (and thus the natural gas/biogas ratio), the key assumption was made that the three gas turbines described in the previous paragraph are representative for other gas turbines and combined cycles within the capacity range considered (20-300MWe).

The aero derivative turbines are available up to about 50 MWe capacity. These gas turbines have a higher efficiency at small scales [1], are multi-shaft and cooled engines [11]. The model for aero derivatives uses characteristics of the LM2500, which was modified for operation with biomass derived LCV gas [12]. There are uncertainties related to the compressor map and cooling system, but the model was tested for wood and the results compared to those presented by Consonni and Larson [1] for wood gasification with little discrepancies (2% for the efficiency). The use of low calorific gases is somehow constrained to the GE modified LM2500-PH [12]. According to Consonni and Larson there is no commercial experience with aero derivative gas turbines as there are with industrial gas turbines operating with low calorific gases [1]. For this work, it is assumed that other aero derivatives may as well be adapted in a similar way as the LM-2500 for the use of biomass gases.

The industrial gas turbines are assumed to be most suitable for combined cycle capacities between 50-300 MWe. Those gas turbines have a more rugged construction, and are capable to tolerate stronger deviations from design operation conditions [1], [13]. Two sizes of heavy frame, industrial gas turbines have been modelled. The so called middle size combined cycle is assumed to be representative of capacities in the range of 50-150 MWe, while the largest modelled plant represent those cycles able to achieve the maximum combustion temperatures currently reached, which is around 1650K [13].

Some gas characteristics of the gas turbines that have been modelled are presented in table 1. The gas turbines presented in table 2 are taken from Gas Turbines World Handbook [10], and represent classes of gas turbines found in the market that are similar to the respective modelled gas turbines categories. They are put together for having similar parameters like pressure ratios and temperatures, which are the most important parameters that determine the efficiency. The aero derivatives are grouped in only one category. All this is done in order to obtain (generic) trend lines that reasonably describe the relations between capacity and efficiency and the heating value of the gas for co-fired BIG/CC systems.

Table 1: Key gas turbines parameters used for the performance modelling in this study.

Gas turbine	Power (MW)	Pressure Ratio	Max T(°C)	Heat ratio (BTU/kWh)	Exhaust air T(°C)
Aeroderivative	21.9	18.9	1531	10655	529
Medium size	70.1	14.9	1561	9915	597
Large size	159.0	14.8	1644	9366	583

An important question is how representative the results presented in figure 3 are for the considered capacity range of co-fired combined cycles in order to give a reasonable

[6] CC schemes can be improved by means of reheating, double or triple pressure schemes and supplementary fuel

approximation for the analyses of scale effects. A good way to verify the calculated results is to compare them to performance data for the combined cycles available in the market using similar gas turbines with 100% of natural gas firing. As these cycles are also featured with single evaporation pressure (the same configuration is maintained through the whole range of gas mixtures), modelling results will on forehand present values significantly lower than these available in the market. On the other hand, the results follow the trends as the commercial cycles. As an example, the cycles based on the LM2500 could achieve plant efficiencies of 50-52% in practice while the cycles for medium frame gas turbines such as the GE S106 FA would be have efficiencies between 53-54%. The large cycles for the heavy frames considered for this work could achieve efficiencies around 57-58 %. The comparison between the results obtained by the model and cycles available commercially is presented in figure 3. It is noticeable that the difference between the results and the cycles available commercially is nearly constant. This difference can be explained due to differences in multiple pressure and reheat configurations The simple configurations considered for this work would be only suitable for the co-fired schemes with large shares of biomass gas. A correction on the results should be made for large shares of natural gas so that the scaling up is compatible with the values of efficiencies available commercially for natural gas. This correction is discussed later. Another observation is that the size of cycles can also be increased by using multiple gas turbines leading to an increase in efficiency due to the use of a more efficient steam cycle.

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for the steam cycle

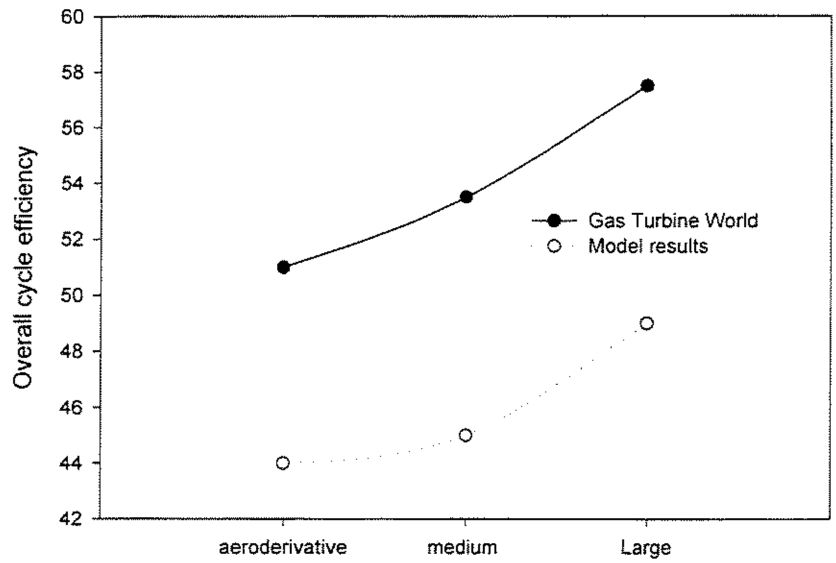

Figure 3. Comparison between modelled cycles for 100% with natural gas and efficiencies of cycles available commercially [10]. The modelling results follow the same trend as the reference data. The lower efficiencies are explained by differences in the steam cycles applied.

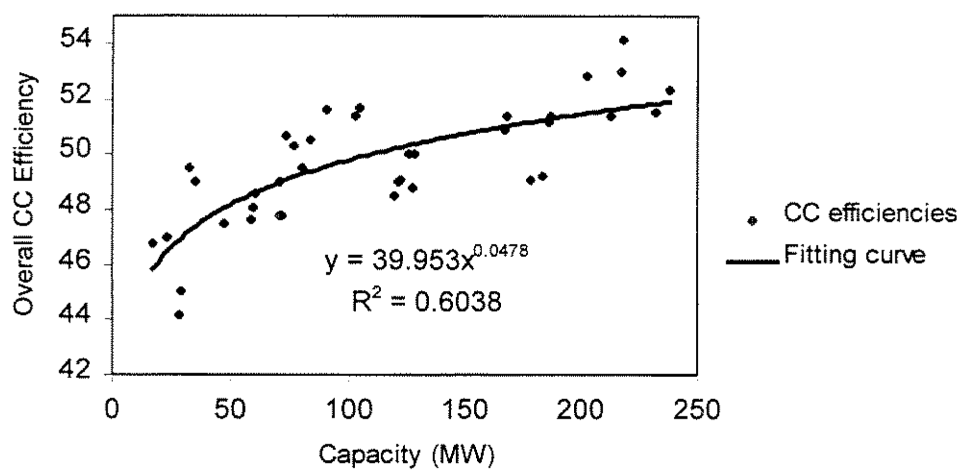

Figure 4. Variation of the efficiency with the capacity [10].

The features of gas turbines available in the market may vary greatly within the proposed ranges [10]. Yet, a number of gas turbines can be selected to support the assumption that the three-modelled cycles are reasonably representative for capacity range considered in this study. For both medium and large industrial gas turbines, the parameters presented in table 1 closely resemble pressure ratios, exhaust air and heat ratios presented in table 2. Some discrepancies are found when comparing the aero derivatives to the modelled one. This is related to the fact that the latter data are based on the LM2500 modified for biomass gases. Therefore the results can deviate from other models. Another issue is the suitability of the gas turbines for the large-load generating combined cycles. The higher pressure ratio's yield lower exhaust temperatures, resulting in less efficient steam cycles. The features of gas turbines listed in table 2 are consistent with requirements for combined cycles [12].

Table 2: Selection of gas turbines representative for the capacity ranges considered; overall, performance data match well with the date used for the performance modelling of the three specific cycles.

Gas turbine models	Output power (MW)	Pressure ratio	Heat ratio (Btu/kWh)	Max temperature (°C)	Exhaust temperature (°C)	Manufacturer
			Aeroderivatives			
LM1600 (PA)	13.44	21.4	9545		487	S&S
LM2500 (PE)	22.8	18.8	9273		523	GE
PGT 25	22.45	17.9	9395		525	Nuovo Pignone
LM2500 (PE)	21.9	18.6	10290		530	Ishikawajima-Harima
			Medium size			
V64.3	63	16.1	9593		531	Bharat Heavy
V64.3^A	68	16.2	9830	1315	589	Siemens
PG6101 (FA)	70.14	15	9980	1287	597	GE
M501	113.95	14	9780	-	543	Mitsubishi
M701	144	14	9810	-	542	Mitsubishi
			Large size			
PG7241 (FA)	171.7	15.5	9420	-	602	GE
PG9351 (FA)	243	14.8	9350	-	597	Hitachi

2.4 A generic description of combined cycle efficiency vs. scale and fuel gas heating value.

A key assumption for the generic model is that the changes in efficiencies will follow the trend lines derived from the previously modelled combined cycles. These changes are associated with the natural gas content in the mixture and the increase of the plant size; effects which are dealt with separately by the model. The aero derivative GT trend line for efficiency variation with the natural gas share is used as starting point for the model. A multiplier is then applied to obtain the curves with higher capacities. The multiplier is a function of capacity and share of natural gas as well as the scale effects.

Figure 5 presents the results for the modelled cycles in the hypothetical case that no de-rating is applied. This would lead to a significant increase in pressure ratio leading to a dangerous operation that is undesirable. Unless the manufacturer guarantees the gas turbine can cope with such operating conditions, this should be avoided by any means. These results have been obtained by the same model described by Walter [5][7], and can be compared to modelling results in figure 2, which included de-rating.

[7] A thermodynamic model able to predict the efficiency for various shares of natural gas that imposes limits for the compressor pressure ratio

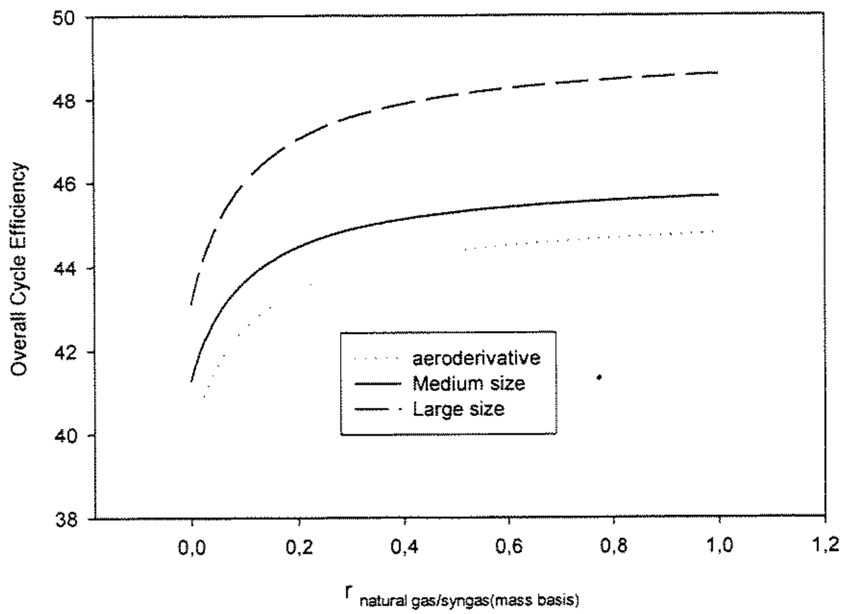

Figure 5. Changes in the energy efficiency of gas turbines with changes in the natural gas/ biomass derived fuel gas shares for various scale ranges. Results were obtained by applying the modelling approach described by Walter et al. [5], [6].

Table 3: Parameters for the multiplier in discontinuous segments

	For shares lower than 10%	Shares >10% (*)	
Constants	De-rating	For capacities up to 150MW	For capacities larger than 150MW
A	-0.63	0.94	0.02
B	1.0	0	0.97

(*) For natural gas shares >=10% there is no need to use any de-rating strategy

The trend lines for both cases, with and without de-rating, were obtained with data fitting performed through non-linear regression using Sigma plot®[8]. Two equations were obtained for the aero derivative gas turbine category. The multiplier described will be applied on these results for the scaling up. Equation {1} resulted from efficiency variation over natural gas shares (r) when *de-rating* is applied. Equation {2} presents the fitting for the cycles with *rated*

[8] Data analysis software

gas turbines. The data derived for rated gas turbines are used for comparisons required in order to isolate the impact of de-rating on costs.

$$\eta(r)_{\text{de-rated GT's}} = (36.06 + 753.55.r)/(1+ 16.34.r + 0.42.r^2) \qquad \{1\}$$

$$\eta(r)_{\text{rated GT's}} = (4.23 + 45.29.r)/(0.106+ r) \qquad \{2\}$$

The following step is to incorporate changes in efficiency related to the scale of the system. In order to obtain the overall efficiency as a function $\eta(r,C)$, a multiplier (M) is defined. The multiplier, that is a function of capacity (C) and natural gas share (r) will add scale effects to equation {1} and {2}. Equation {3} presents the relation between efficiency, natural gas share and capacity. The function $\eta(r)$ can be either equation {1} or {2} The multiplier M varies with capacity and natural gas share according to equation {4} The multiplier is, in fact, a discontinuous function. This discontinuity is based on the need of de-rating as well as a different increase pace for higher capacities[9]. The first part of the function is defined for shares of natural gas up to 10% in a mass. Other constants are defined for shares larger than 10%, which are in turn different for capacities larger than 150MW. This capacity is set a bit arbitrarily and is fixed in between the capacity of the medium and large scale cycle range. The constants {4} are presented in table 3.

$$\eta(r, C) = \eta(r).\, M \qquad \{3\}$$

$$M = (\eta_{(C\ \text{biomass})} / \eta_o)\,(a.\, r + b) \qquad \{4\}$$

The function $\eta_{(C\ \text{biomass})}$ in equation 1 describes the efficiency increase when the capacity for a BIG-CC (no co firing) is increased. The function is obtained from the relation presented in figure 4. The constant ηo represents the efficiency of the cycle based on the aeroderivative GT when burning 100% of biomass initial efficiency used in the scaling up model. Both $\eta_{(C\text{syngas})}$ and ηo will differ for de-rated and rated gas turbines together with $\eta(r)$ that is based on equation {1} or equation {2}. The trend lines presented in figure 6 are described by equations {5} and {6}. Equation {5} is applicable when de-rating is imposed. Equation {6} describes the cases with rated GT`s.

Finally, the capacity is calculated by formula {7} that is a recurrent function as the efficiency depends on the capacity. The results are calculated using an excel spreadsheet model.

$$\eta_{(C)\ \text{de-rated}} = (36.06+753.5.r)/(1+16.34.r+0.42.r^2) \qquad \{5\}$$

$$\eta_{(C)\ \text{rated}} = (4.23 + 45.29.\ r)/(0.126 + r) \qquad \{6\}$$

$$C = m.\ (r.\ PCI_{NG} + (1-r).\ PCI_{\ \text{biomass}}).\eta\ (r,C) \qquad \{7\}$$

Where parameters are defined as:

η:	Combined cycle efficiency
C:	capacity
r:	ratio gas natural/biomass
PCI_{NG}	PCI for natural gas
$PCI_{\ \text{biomass}}$	PCI for syngas
m:	total mass flow

Correction for the case with natural gas: Because the cycles are based on a simple configuration that is suitable for the use of LCV gases, a correction had to be made for the situation that large shares of natural gas are used. This correction is necessary for cost effectiveness studies as the cycles available in the market have higher efficiencies than those obtained by the model. This correction implies that the results for the cases with 100% of natural gas will follow the trend line presented in figure 4. The example for the correction with the aero derivative gas turbine is shown in figure 6. The correction of the base trend line starts from a percentage of 30% for the natural gas share in the fuel mixture. In fact, this cycle could

[9] For the higher capacities, efficiencies increase at a higher pace as they benefit from higher temperatures.

achieve efficiencies around 51-52% [10]. This correction is applied to all trend lines so that the efficiencies of cases assumed to be running on 100% of natural gas in fact equal the values observed for commercially available combined cycles.

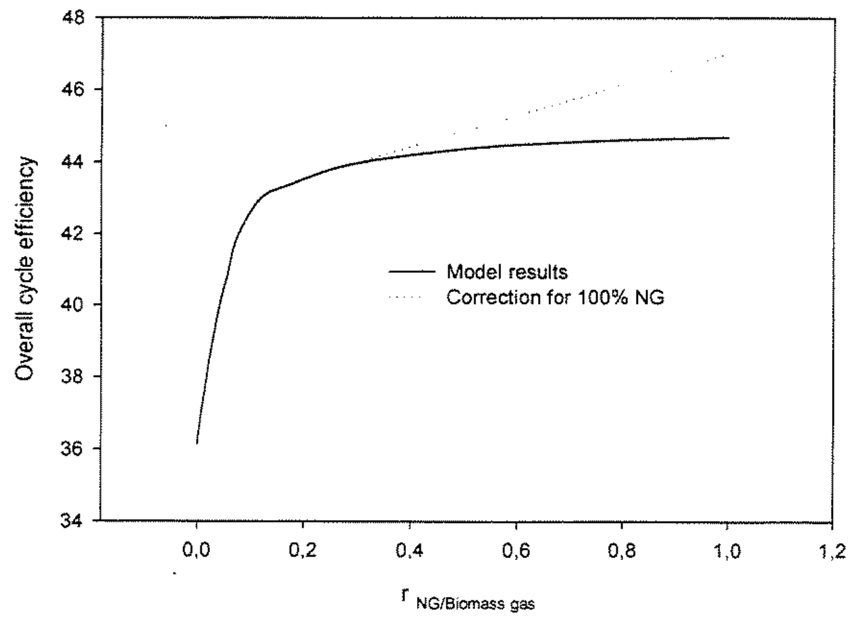

Figure 6. Correction of the model results for the combined cycle efficiency obtained for de-rated turbines and single steam cycles for the situation high shares of natural gas are used. The correction ensures that for 100% natural gas firing the efficiency equals efficiencies observed in practice (see figure 4).

3. COST ANALYSIS

A key reason to consider co-fired combined cycles is to obtain reduction on cost of electricity from biomass due to economies of scale and gains in efficiency. Small biomass fuelled gasification plants can benefit from the high efficiency and low capital costs of large combined cycles [4]. When the size of a co-fired plant increases, it consumes larger amounts of natural gas, biomass gas or both. The increase of biomass use results in higher costs associated with logistics like transportation and storage, because on average the biomass has to be collected from a larger land area, resulting in increased transport distances.

On the other hand, when the amount of contracted natural gas by a facility (or customer) increases; a reduction on gas price can be obtained based on the class (or volume) of consumption. Table 4 summarises the way natural gas prices are determined for different consumption classes in Brazil. For thermoelectric (co-)generation plants prices range from 65 to 78 US$/Mm^2 [14].

Table 4:The prices of natural gas in Brazil, depending on consumption classes, the final tariff is equal to C+ (D*V), C and V representing a constant and variable part respectively (values, see table) and D representing the difference between the measured and minimum consumption in each class range [16].

Classes of consumption (million Nm^3 per month)	Thermoelectric capacity (MWe)	Constant (C) (US$)	Variable (V) (U$/Mm$^{3)}$
0- 2	0- 40	0,00	78
2-4	40-85	156,421.5	76
4- 7	85-150	309,026.9	74
7– 10	150-217	718,528.9	72
10– 20	217-440	749,671.0	70
Above 20	Above 440	1,455,457.3	65

Reductions on investment costs can be attained as the combined cycle size increases. Economies of scale can reduce combined cycle costs from U$850/kW at about 20MW to costs lower than US$400/kW at 300MW [10]. Scaling up the biomass equipment further lowers the investment costs, which are partly considerably affected by economies of scale. The approach for quantifying economies of scale on system component level is taken from Faaij et al., (1998) [3]. This approach assumes that all components are in fact scaled up (but with different scaling factors depending on the type of equipment considered) and that the capacity is not increased by building multiple components (which is reasonable for the capacities considered in this study).

The Institute of Gas Technology (IGT) and Batelle Columbus Laboratories indicated that single vessels gasifiers may be realised to a capacity of 2,000 dry tonnes per day (over 400

MWth-input), provided that the building site is accessible by for heavy transport by water [3]. The thermal input for the largest plant considered in this study amounts about 700 MWth, which is beyond the limit indicated by IGT and Batelle. As a simplification, it was assumed that the gasifier can in fact be scaled up to that capacity. The consequences of doing so will be discussed later.

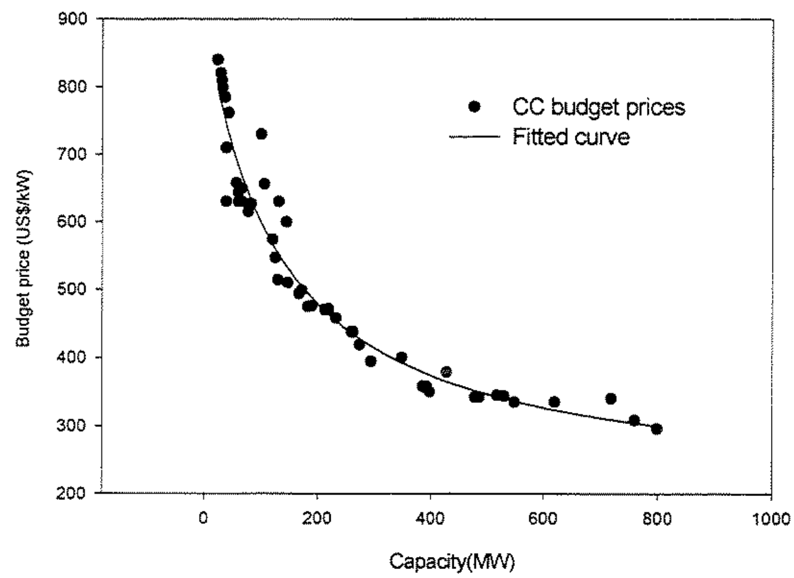

Figure 7. Turn-key investment costs of combined cycles versus capacity [10].

3.1 Economies of scale for the combined cycle

In order to evaluate the economies of scales when the size of the plant is increased, a trend line function that describes the investment per kWe installed versus the capacity is derived from known combined cycle costs as reported in the Gas turbine World Handbook [10]. These turnkey costs result in a (generic) trend line which is presented in figure 9. The trend line obtained through data fitting results is described with equation {8}

Costs (US$/kW) = (956.15+2.039. C) / (1+0,0096 C) {8}

Where C is the capacity of the plant when fuelled with NG (MW)

3.2 Costs of GT modifications

Some technical adaptations of gas turbines are required to burn Low Calorific Value gases. These modifications are necessary due to an increase in the pressure loss that is associated with a much larger volume going through the gas turbine[10]. The type of modification depends on the gas turbine and the heating value of the low calorific gas. The modifications might involve the replacement of the nozzle, the burner or even the replacement of the complete combustion chamber. A dual fuel system (natural gas and biomass gas) is necessary since there are ignition and flame stability problems during the start off [16]. The GE LM2500-PH has been adapted and tested for the use biomass derived gas [12]. This gas turbine has the advantage of the design for steam augmentation, so it can accept large volume gas flows. The fuel nozzle has to be replaced and a dual fuel circuit installed. The adaptations may be different for other aero derivative and industrial gas turbines. GE industrial gas turbine modifications and costs are listed in table 5. These data were provided by a GE gas turbine supplier and reported in: [13]. The modification costs are defined as a percentage share of the gas turbines prices. In this analysis the function depicted in figure 4 is used to include this cost factor in the scaling model. The adaptation costs for aero derivatives were assumed to be 5% of the gas turbine while the costs of modifications of industrial gas turbines are defined by the values presented in table 5 for different co-firing percentages. The reported data are largely based on estimates proved by General Electric. In practice, for specific machines, the costs may vary. Furthermore, data on modification costs may change as the market develops. Such information is however hard to obtain.

Table 5:Costs ranges for modifications for burning LCV gas of industrial gas Turbines [12].

Modification	% LCV gas firing (energy basis)(*)	Modification cost (% of GT capital costs)
Burner modification	<1	2%
Replacement of burner for one dual fuel burner	1-25%	5%
Replacement of the complete combustion chamber	>25%	20%

(*) Share based on a gas with a LHV =6.13 MJ/m³

3.3 Scaling up gasification systems

Economies of scales were apply to all gasification and gas cleaning components. Those components can be scaled-up according to throughput capacity of solids or gas. This approach assumes that every component is in fact scaled up instead of building multiple numbers to achieve the capacity. This seems to be reasonable for capacities up to 400 MW_{th} [3]. Faaij et al. (1998) gave cost data per component for a 30 MWe BIG/CC system [3]. Those data are used as the starting point for the modelling efforts in this paper. It should be noted that they report cost projections for first generation commercial plants, which are very high, but also likely to drop dramatically after a few more plants have been realised. It seems however realistic to consider the high cost levels for the base calculations this study as co-firing is suggested as a short-term option to improve the cost-effectiveness of BIG-CC technology. In the sensitivity analysis the impact of those cost data on the results will be evaluated further. The general relation between costs and capacity is given by the equation below:

$$COST_{size2}/COST_{size1}=[SIZE_2/SIZE_1]^R \qquad \{9\}$$

Where:

$COST_{size\ 1}$	is the cost of the base system[11] for which the cost data are known (table 6)
$COST_{size2}$	is the cost that is going to be calculated
SIZE2	is the system throughput
SIZE1	is the base system throughput (i.e. 8.4 kg/s of wood)

The costs per component for the base BIG/CC system and values of R (scale factor) are presented in table 6 are taken from Faaij et al. (1998) [3].

[10] 8-10 times the volume of natural gas depending whether de-rating is applied or not.

Table 6: Costs for the biomass equipment (base values for a first generation BIG/CC system) and applicable scale factors per component used for further model calculations.

Equipment	Base system costs* (MU$)	Scale factor (R)
Conveyers:	0.32	0.8
Grid	0.36	0.6
Dryer	6.7	0.8
Iron removal	0.28	0.7
Feeding system:(2 screws)	0.32	0.7
Tar cracker:	2.8	0.7
Gasifier:	2.8	0.7
Cyclones:	2.2	0.7
Gas cooling	2.6	0.7
Baghouse filter	2.2	0.65
Condensing scrubber	1.4	0.7
Compressor	2.17	0.85
Gas/gas heat exchanger	2.8	0.7
Equipment of gasification:	26.9	

*Expected costs for the short-term in million dollars.

4. SUPPLY AND LOGISTICS

Sugar cane trash availability: The biomass feedstock used for the BIG-CC system is trash, produced during the harvest of sugarcane. Like other agricultural residues as wheat and rice straw, trash needs to be collected from the field, baled and transported prior to conversion. Compared to straw, costs for trash collection tend to be relatively low in sugarcane plantation regions in Brazil because the yield of biomass residues per hectare is very high. A typical value is a yield of over 11 tons of dry trash per hectare of planted area in São Paulo[12] [17], [18]. Including topographic constraints and considering that part of the trash is left in the field, the net availability lays between 100 and 150 PJ per year [8]. We will use these values for further calculations in this study.

Collection costs: In order to determine the collection costs we use data from recent field tests of sugar cane harvest and trash collection equipment [18]. In this project, the technical,

[11] A 30MWe Biomass Integrated Gasifier/Combined Cycle system fired by clean wood, of 40% net electrical efficiency.

[12] Productivity in Sao Paulo: 83.8 tons of cane per hectare, amount of trash dry matter in the cane 15%

economical and agronomic feasibility of the use of BIG-GT technology for power generation using bagasse and trash was evaluated.

The trash collection involves the ranking, baling, loading and thread. The first step in the process is the ranking of the trash left on the field. This process places the trash in lines in order to avoid eventual fire propagation and to facilitate the baling. The costs associated with the baling make out the largest part of the collection costs. Those costs depend on the type of bale and on the performance of the baler. The costs used in this study are assessed for the baler JS-90 that produces round bales [18]. The round bale presents lower costs compared to rectangular baling, as it can bale 33% more residues and the maintenance costs for the rectangular bales are higher. Round bales would also lead to fewer losses when stored in the field. On the other hand the transportation costs for round bales are higher [18].

The costs for trash collection are considered constant per ton of trash. The energy content depends on the moisture content of the trash, which in turn depends on the shares of dry leaves, green leaves. The moisture content can be lowered to 25-30% in case it is left in the field. The collection costs therefore vary between US$1.4-2/GJ. Costs are composed of the investments and operation (fuel, labour) of machinery and the thread that are used to tie the bales. Costs are listed in table 7. Cost estimations are conservative as they are based on the costs of the first set of field tests. It is likely that considerable costs reductions are possible once the collection technique is optimised further [19].

Cost for transportation and storage are treated separately in the following sub-sections.

Transport: The transportation costs are estimated based on data from the mentioned field trails for trash collection and baling and on costs for sugar cane transportation. An approach demonstrated by Dornburg and Faaij (2001) was used to calculate the transportation distances and related costs [20]. The calculation is based on the assumption that the (average) distribution of biomass over an area is constant (expressed as biomass distribution density). Another assumption is that the biomass amount m (for one year long operation) is transported over a marginal transport distance d. This marginal distance is the radius of a circle in which the biomass is spread with the given distribution density. Thus, the marginal distance that increases with the square root is given by equation 9. By means of identical areas, the total number of ton*km are converted into average distance (d`) and average mass (m`), to be calculated for a conversion unit with a specific capacity and load factor. These average distances are the basis for further cost calculations. Figure 8 illustrates the principle of the biomass transport model graphically.

$$d\,(m) = (m/D_b*\pi)^{0.5} \qquad \{10\}$$

Where,

d(m) is the marginal transport distance (km)

m is the amount of biomass for transportation (tons per year)

D_b is the biomass distribution density (ton/km^2)

From equation (9) it follows that the total ton*km (d*m) to transport the mass m is the integral of the marginal distance,

$$d*m = 2/3*m^{1.5}*(D_b*\pi)^{-0.5} = d` * m` \qquad \{11\}$$

Where

d*m is the ton*km to transport m (ton*km per year)

d` is the average transport distance

m` is the average amount of biomass for transportation (tons per year)

The final outcome and basis for transportation costs calculations are,

$$d' = 2/3*m^{1.5}*(D_b*\pi)^{-0,5} \qquad \{12\}$$

$$m' = m*2/3 \qquad \{13\}$$

The biomass distribution density was estimated on the basis of data for the region of Piracicaba (one of the main areas of sugar cane production in Sao Paulo). This is a region with a high density of sugar cane plantations (around 35% of its territory) and quite representative for other areas with a high density of sugar cane plantation densities which are found through São Paulo State. The data presented in table 8 were used to estimate residue production and cost calculations for logistics.

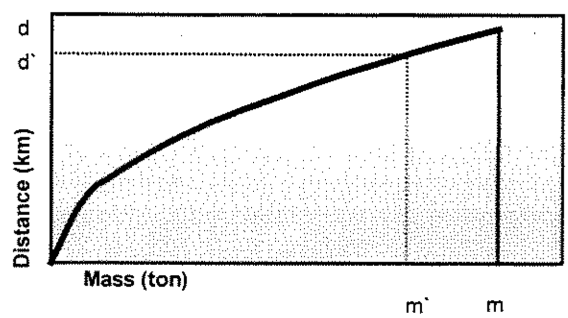

Figure 8. Graphical representation of the relation between the average transport distance and the amount of biomass required for a conversion unit, assuming the biomass is distributed evenly per unit of land surface.

The costs for transporting the biomass will depend on the distance as well as the bales` shape and density. The transportation cost in the mentioned field tests amount approximately US$4.7 for round bales and over a distance of 10km. The variation of this cost with the distance is assumed to be the same as that for sugar cane transportation [18]. This means that the cost US$4.7 at 10km, taken as the reference, is determined to be a percentage of sugar cane costs transportation. This percentage is maintained all over the transportation range (0-65km). The variation of trash transportation is then determined (see table 9).

Storage: Storage facilities are necessary for the operation of the power plant during the off–season. During the harvesting, the trash can be stored in the fields and no additional costs are included for this. During the rainy season, a storage concept using plate metal buildings is proposed. The related costs are taken from rice straw storage costs. The metal building is selected because it was found to be the cheapest in a comparative study for Californian conditions [21]. Due to the (assumed) application of closed storage, dry matter losses are assumed to be negligible. The storage capacity is assumed to be larger than 20000 tons, which means no significant variation of the costs with the scale. For the case with clear span, concrete pad and salvage value of 50%, the costs for storage amount about US$ 6.00/ton.

Total costs of logistics: The cost breakdown of the logistics for supplying sugar cane trash consumed by a 100 MWe BIG-CC plant situated in the Piracicaba region is presented in figure 9. At this capacity the model predicts 40% efficiency for a plant that consumes only biomass. Assuming a load factor of 0.8, the annual consumption amounts 400 kton of dry trash. This amount of trash is obtained from 714 thousand tons of bales[13]. These bales are transported over an average distance of 36km. The trash available for collection assumed to be distributed by a constant density of 132 ton/km^2 (35% of the area covered by sugar cane plantations). This density already includes a topographic constraint of 60% used for mechanical harvesting, 50% of the trash left on the field and 15% of ton dry matter per ton of cane. The amount of land needed would be about 3,000 km^2.

The baling is always the most significant fraction of the total costs for logistics for the capacity range considered (20-300MW). Transport is the only cost factor that depends on the conversion system's capacity. For the case assumed here the average transportation distance amounts 39 km.

Table 7: Estimated costs for collection and baling per ton of sugar cane trash as derived from field tests.

Steps	Ranking	Loading	Baling	Thread	Total
Costs (US$/ton)	1.3	2.4	9.6	0.6	13.9

[13] Impurities :5.6% of earth, 14% of cane in the bale and a moisture content of 30%.

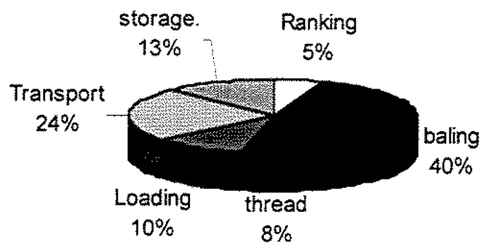

Figure 9. Costs breakdown of the total logistic chain for supplying sugar cane trash to a 100 MWe BIG/CC unit in the Piracicaba region in Sao Paulo State.

Table 8:Data used for the calculation of average biomass distribution density (sugar cane trash) for the Piracicaba region.

Harvested sugarcane area	1227 km^2
Total area of the region	3515 km^2
Sugarcane Productivity	8030 ton/km^2
Trash average density (D_b) (*)	126 ton/km^2

(*) Assuming that 50% of the trash is left on the field, 60% percent mechanisation rate, 30% of the trash is recoverable.

Table 9:Estimated transport costs for round bales at Piracicaba

Distance up to: (km)	5	10	15	20	25	30	35	40	45	50	55	60	65
US$/ton	2.8	3.5	4.7	5.9	6.9	7.9	8.9	9.9	11.1	12.2	13.1	14.2	14.8

5. RESULTS

This section presents a brief analysis on benefits of increasing the scale for biomass fired BIG-CC`s considering rated and de-rated gas turbines, an extensive analysis on cost benefits for the biomass base power generation in co-fired plants for short term conditions, an outlook for somewhat longer term and a sensitivity analysis.

5.1 Efficiency and costs for BIG-CC`s fired with biomass only in relation to scale.

Figure 10 presents the results for efficiency variation with the scale for combined cycles running on natural gas only as well as BIG-CC`s burning 100%. These results for BIG/CC`s are derived from the results given in figure 2 and 4 for the 100% biomass firing cases (capacity range 20-300MW). These curves are compared to that derived from commercial data taken from Gas Turbine World (2000), which were presented in figure 5 [10]. This graph clearly shows that de-rating hampers efficiency gains with scale. This can be observed by comparing the cycles with de-rated gas turbines to the same cycles using rated gas turbines; the difference between the rated and de-rated gas turbines cycles represents the impact of de-rating on the cycle efficiency. Figure 10 illustrates the maximum difference in efficiencies that can at least partly be reduced when using natural gas for co-firing (direct, atmospheric) BIG/CC systems.

Based on the efficiency results presented in figure 10, the costs of electricity calculated for BIG-CC systems, which are 100% fired with biomass are presented in figure 11, within the capacity range between 20 – 300 MWe for both de-rated and rated gas turbines.

The biomass cost varies between US$18 to US$ 22.00 per ton delivered at the plant, depending on transport distances. The investment costs vary from US$ 3600 to US$ 1700/kWe[14]. Operation and Maintenance amounts US$4/MWh for the combined cycle plus US$4 per ton of processed biomass [3]. A 0.8 load factor, 12% interest rate and 25 year lifetime are assumed.

For both curves, the COE drop dramatically with the scale, especially at low capacities (up to 100MW). The increasing costs with transportation have some impact on the high capacities

(>150MWe), causing the curves to flatten. This effect is more easily observed for the results with de-rated GT`s as the efficiency increases at lower pace for large scales (compare with figure 10). The higher transportation costs for the larger capacities are however offset by gains in economies of scale and efficiency, pleading for large scale units. These results demonstrate the impact of the de-rating on energy costs as a function of scale. These impacts are strongest at smaller scales in which de-rating can lead to a COE up to 10% higher than those with rated gas turbines. While the impact of de-rating is less severe for middle size cycles, the efficiency penalty of de-rating gets stronger for larger scales as the de-rating has again a stronger impact on the larger cycles that are designed for operation at high combustion temperatures.

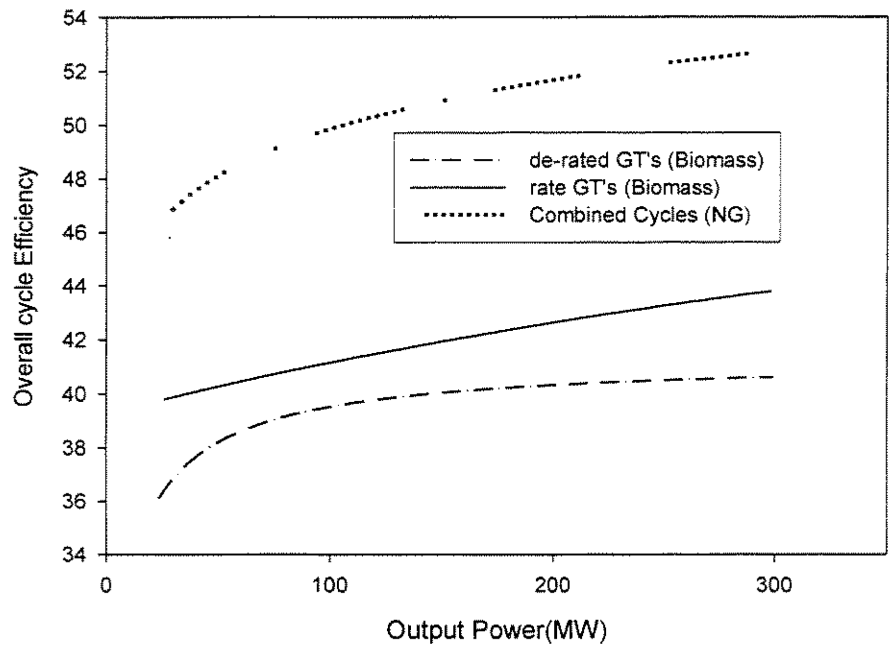

Figure 10. Comparison of the efficiency for 100% natural gas fired combined cycles and 100% biomass fired BIG/CC systems with rated and de-rated gas turbines in the capacity range of 20 – 300 MWe.

[14] Engineering (15%), site-preparation (5%), fees, overheads and profits (10%), start-up (5%) and building interest (25%, first year, 75% second year)

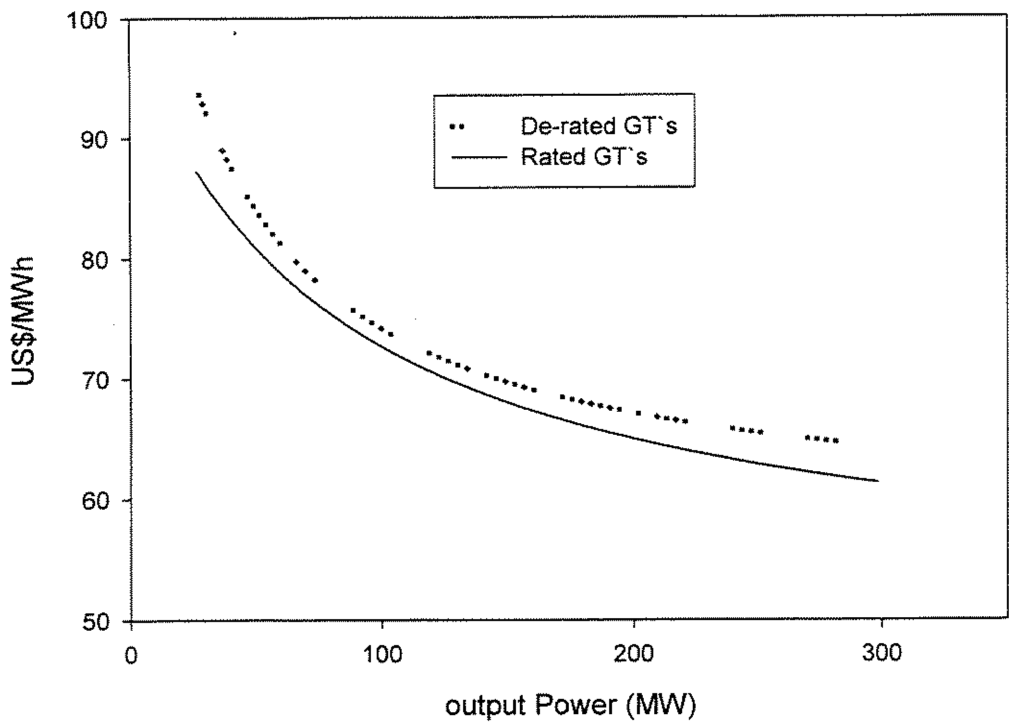

Figure 11. Calculated Costs of Electricity for 100 % biomass fired BIG-CC systems in relation to their capacity for both rated and de-rated gas turbines. Data assume first generation BIG/CC technology and conditions for Sao Paulo State-Brazil.

5.2 Co-fired BIG-CC`s

The variation of the COE with the scale for co-fired BIG-CC`s are presented in figure 12. The biomass costs varied between US$ 1.4-1.8/GJ, while natural costs were between US$ 1 –2/GJ [15]. Other assumptions for cost calculations are the same as described for 100% biomass fired BIG-CC`s.

The mixing with natural gas leads to a considerable reduction on energy costs. The average costs for a large combined cycle using 30% of biomass would be comparable to a 50MWe power plant on natural gas only (~ US$ 40/MWh). These costs, however, represent average values for both biomass and natural gas based capacity and therefore they are not representative of the benefits of co-firing for biomass only.

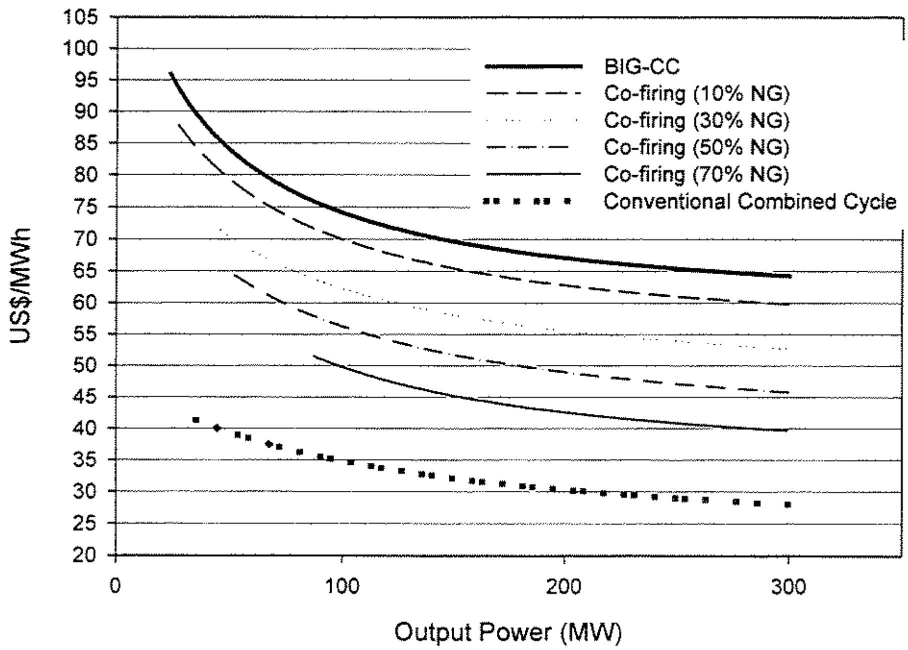

Figure 12. Calculated COE (including logistics) over a capacity range of 20 – 300 MWe of co-fired BIG/CC systems with different ratio's of natural gas.

In order to isolate the COE from biomass only, a correct allocation of the various costs factors is needed. In order to do so, the actual cost for biomass power in a co-fired plant is defined as the average price (presented in figure 12) plus the difference between this value and the COE for a combined cycle using the same amount of natural gas as the co-fired plant. This allocation fully allocates the cost penalty of the (more expensive) share of biomass derived fuel gas production to the part of the electricity that is produced from biomass. For instance, a co-fired plant with 30% of natural gas firing on an energy basis and a capacity of 300 MW would be producing 210 MW of its energy from biomass and 90 MW from natural gas. The generation of 90MW of power from natural gas is performed at a considerably higher cost if the average COE of the plant (US$52.7/MWh) is considered compared to natural gas only. The difference between this average and the costs for a combined cycle running on natural gas at the same capacity (US$ 35.5/MWh) should therefore be allocated to COE from biomass. The difference in costs per MWh (US$17.6/MWh) is added to the COE from biomass. The outcome is a cost for biomass of US$ 60/MWh. This allocation rule was applied to the all the curves from figure 12 and the results of doing so are presented in figure 13.

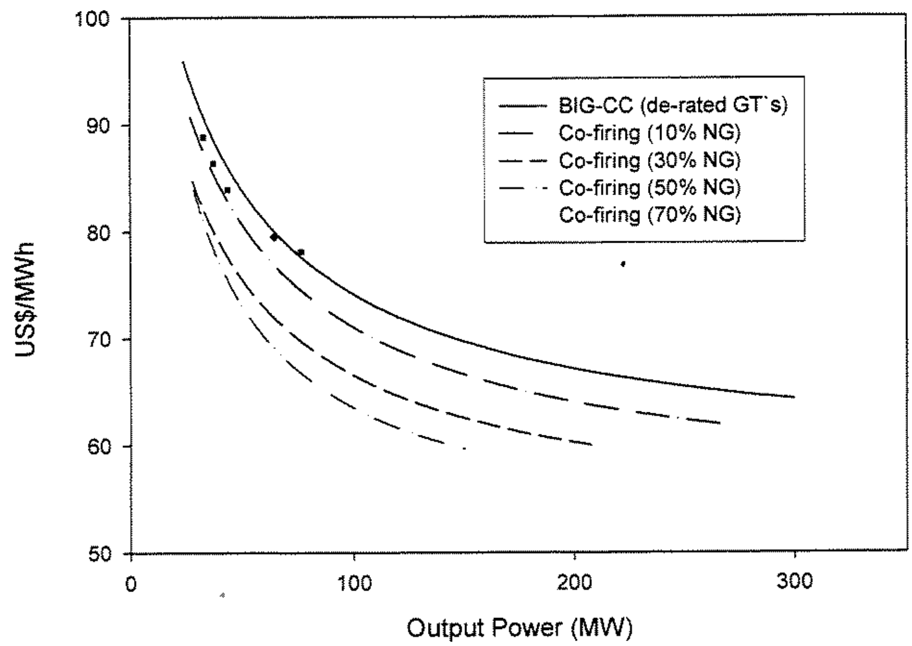

Figure 13. COE from biomass only in various co-firing schemes in relation to the capacity of the system, with full allocation of cost penalties of the natural gas share to the bioelectricity costs.

Results presented in figure 13 show the actual gains for biomass power when co-firing is used, compared to the base-line scenario of 100% biomass firing (the upper line in graph 13). The advantages of a co-firing scheme are evident. In a 200MWe co-fired plant, 100MWe of biomass power can be generated at a cost that is 15% less than a BIG-CC of the same capacity would result in (see figure 13). For a 300MWe plant co-firing 30% of natural gas, the maximum gains for the 210 MW biomass power would be around 10% over a BIG-CC using biomass only. The COE from biomass can drop from US$ 96.00 to US$ 59.00, comparing the highest price for biomass generation with the lowest costs for a co-firing mode. This represents a gain of about 39% that is achieved with gains in efficiency and scale effects.

However, when considering a co-firing scheme with 70% of natural gas, there are practically no gains for biomass power when compared to the BIG-CC running 100% on biomass. In this case, the allocation leads to COE from biomass in a co-firing plant that can become even higher than power from biomass alone. This result suggests that the costs for a 30% share the costs allocation lead to a very expensive biomass share, which can be explained by the effect that the economies of scale for the biomass parts become very limited. The benefits with scale and higher efficiency associated with co-firing do not outweigh those higher specific investment costs. Furthermore, the results for smallest capacities (20-30MWe) at the 50% are the same as those for a 30% share. These results show that there are limitations for gains that can be obtained for biomass generation with co-firing. Under considered assumptions the lowest cost levels are obtained for a 300MWe co-fired plant based on 50% of natural gas.

The variation of biomass based COE with cost allocation over various shares of natural gas at various capacities is presented figure 14. This figure shows more clearly the minimum cost levels for the biomass based COE in co-fired schemes at co-firing percentage of about 50%. Between 50-60% the results for biomass are already higher than the case with 100% of biomass for those capacities. When the share is about 70%, the costs start to exceed the equivalent biomass capacity in a 100% biomass BIG-CC plant as can be seen in comparison with graph 13.

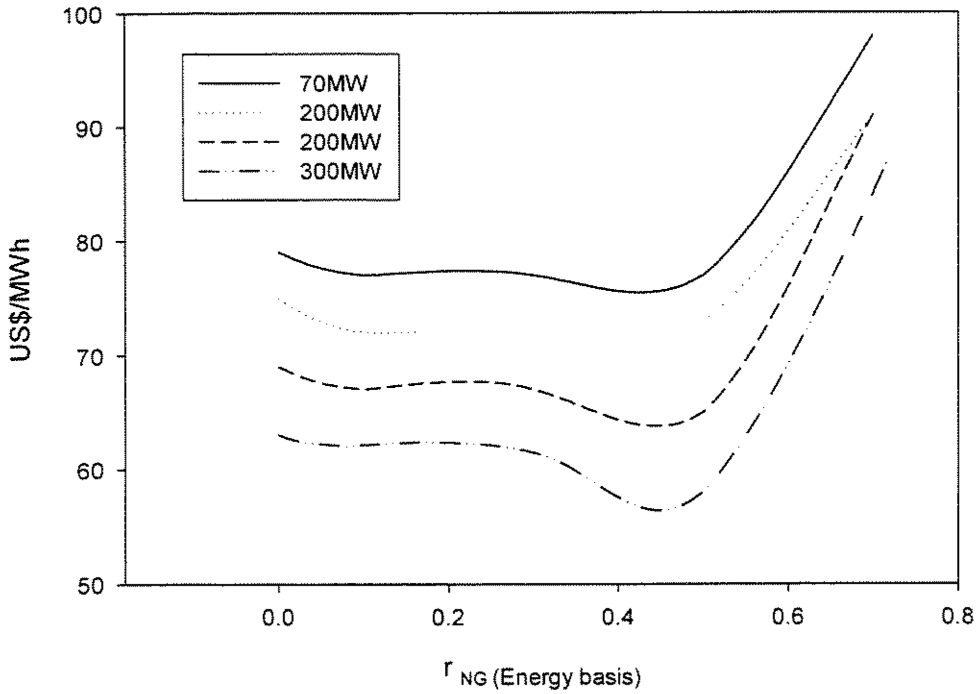

Figure 14. Variation of COE over natural gas shares for the same capacity.

5.3 Sensitivity analyses

A spider diagram is presented in figure 16 as sensitivity analysis of a 100MWe plant fired with 50% NG. The efficiency is the parameter to which the costs are the most sensitive, followed by the combined cycle investment costs. Cost reductions in the combined cycle capital costs have no particular benefits for biomass generation in relation to natural gas though. The efficiency can still be optimized for both co-firing leading to further costs reduction. The third more important parameter is the capital cost of the biomass pre-treatment, gasification and gas cleaning equipment.

The price for the gasification equipment is likely to be substantially reduced after the first commercial plants. The estimated (short term) investment for a BIG-CC system using trash as a fuel lays around US$ 3400/kW for a 24MWe plant. The expected capital costs reductions for such a system in a long-term is rather uncertain, but a fully commercial plant can reach costs as low as US$ 1230-1420/kW for a plant based on a LM2500 and atmospheric pressure directly heated gasification [22]. This capital cost can be achieved by emphasizing careful engineering design, and "cookie cutter" production of standard design, and maximizing factory assembly. The price for the gasification and cleaning system could easily get to half the value considered here already for first commercial plants [3], [23].

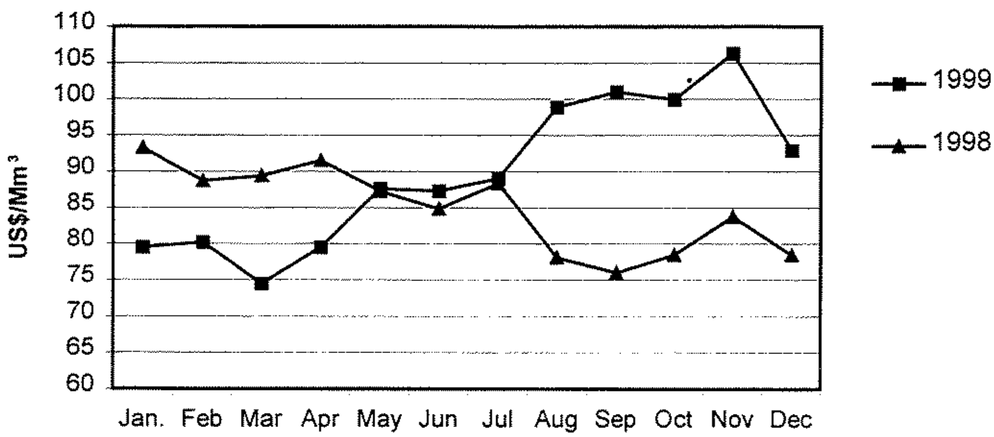

Figure 15. Natural Gas Price variation in US Market in 1998-1999 [24].

In case the biomass gasification equipment for the 30MWe gasification plant, which is the basis for the scaling up, would be lowered by 50%, biomass electricity costs would be lowered by 38% for a 150 MW biomass from a 50% natural gas share co-fired plant. For a co-fired plant with 300MW being 50% of this power from biomass could reach a COE as low as US$ 40.00/MWh for biomass power (including cost allocation).

Some cost reduction can be expected for biomass collection as well. As the trash collection is expected to become common practice, these first estimated costs would probably be reduced. According to Macedo (1999), it is possible to reduce the costs from US$ 18-22/ ton of baled trash to US$ 10/ton [24]. Moreover, there has been substantial devaluation of local currency and despite the fact that equipment is partially imported and hence rated in dollar, some costs reductions should be expected for maintenance, operation and transportation.

The energy prices are less sensitive to trash supply costs though. If trash costs would be lowered by 50%, the biomass energy prices would be around 78% of the costs calculated previously. The energy prices show very little sensitivity to the transportation costs.

The COE are almost as sensitive to natural gas price as they are to trash at this capacity and share of fuels. The price of natural gas may rise with the development of natural gas market. Price fluctuations are common in established gas market. As an illustration, figure 15 presents the average price variation for the market in US over two years. Within this period, the price varied from US$75 to 106/MWh, an increase of 40% [25]. Such an increase would lead to a 30% increase on costs of electricity for a 100MW-combined cycle on natural gas. On the other hand, in a co-fired plant with the same capacity but generating half of this capacity from biomass, the increase on costs would be about 5%. Future prices of natural gas are hard to predict, but do present a risk factor to investors. The combined use with biomass can reduce this risk and increase the (fuel) flexibility of new power generation capacity, which may be especially relevant in an unestablished natural gas market as in SE Brazil.

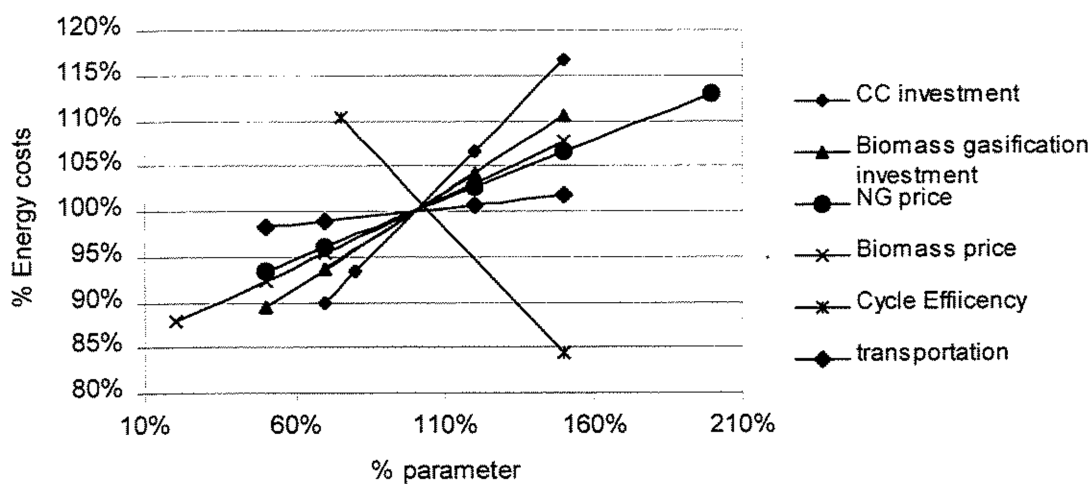

Figure 16. Sensitivity analysis of a 100MWe co-fired BIG/CC plant with 50% of natural gas.

A comparison of the cost breakdowns of power generation by means of BIG-CC`s, conventional combined cycles fired with natural gas and co-fired plants is presented in figure 17. It can be observed that the relative cost shares for fuel, investment and costs for BIG-CC and the co-fired plant are quite similar. The shares for fuel and O&M can be divided in almost equal shares for the natural gas and biomass fuel gas part.

In view of very likely reductions on investments costs for biomass gasification and gas cleaning [3] and trash logistics [24] an alternative cost scenario is presented in figure 18 (similar in set-up as figure 12). These results are based on the assumption that investment costs for the gasification system and trash logistics can be cut in half. These results also assume a scenario with a 50% increase on natural gas price. The curves show that co-firing becomes less beneficial than the previous scenario especially for smaller capacities (<70MWe). Again, these values are not representative of biomass power and costs allocation should be performed. Costs for biomass power in this new scenario are presented in figure 19. In this scenario, the COE from biomass go down to US$42.00 at 150MW (300MW, co-fired 50%), which is about 20% less than the equivalent capacity when only biomass would be used (compare to figure 18). When comparing these results to those presented in figure 13, three aspects are evident: the results for the maximum capacities for different co-firing modes get very close (US$42-43/MWh). The costs for a 70% natural gas share do not increase for the capacity range considered (20-300MW) and the results for the smallest capacities are about the same for the shares between 30-70% at the lowest capacities (20-30MW). For this new scenario that considers new prices for the fuels, the benefits for the biomass shares in a co-fired scheme are thus further improved. Moreover, the limitations for benefits with co-firing were only observed for the plants with the lowest capacities. The benefits for co-fired schemes will be further improved by the reduction of investments associated with biomass gasification.

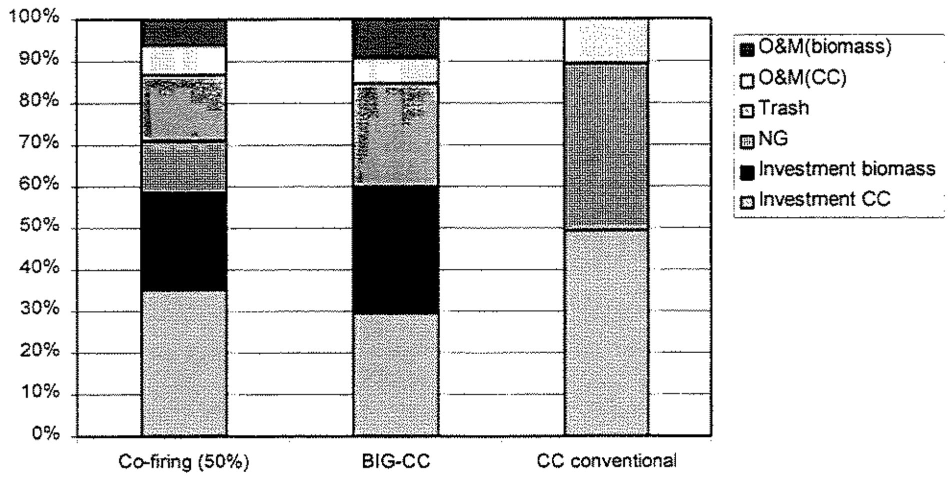

Figure 17. Relative cost breakdowns for the three categories of power plants considered: 50% co-firing, 100% biomass and 100% natural gas fired combined cycles at 100 MWe total capacity.

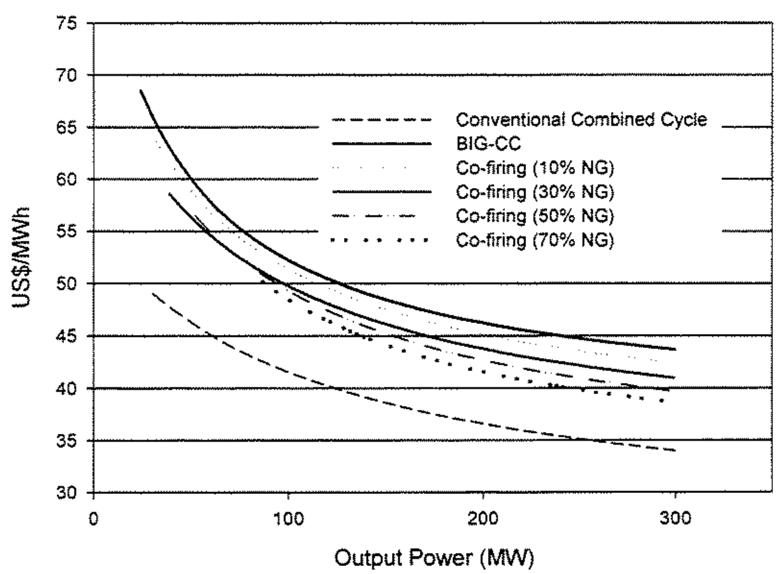

Figure 18. Results for the COE with assumed cost reductions regarding biomass supply costs (50% reduction), the investment costs of the biomass conversion part (50% cost reduction) and an increase of 50% on natural gas costs.

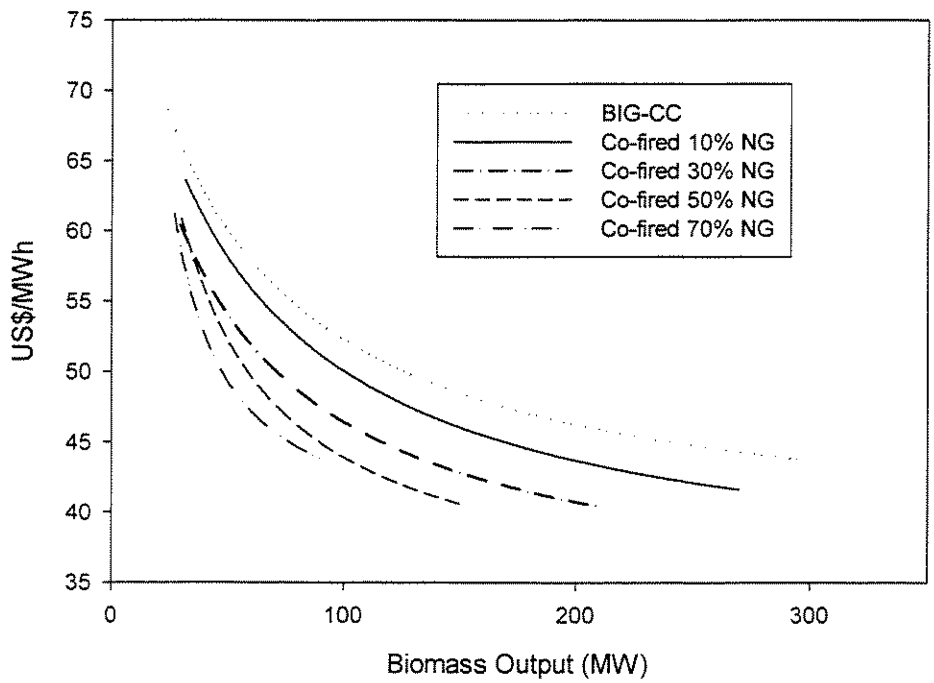

Figure 19. COE for the biomass power share of co-fired plants for the cost reduction scenario.

6. DISCUSSION AND CONCLUSIONS

This work aimed at analyzing the cost (and efficiency) benefits associated with co-firing combined cycles for biomass based power generation. In general, co-firing substantially increases the efficiency of the production of electricity from biomass [5], [7] and becomes more competitive due to economies of scale, compared to biomass firing only. A generic model proposed in this paper, applicable to a 20-300Mwe scale range, incorporated the efficiency increases due to mixing LCV gas with natural gas and the increases in plant size. The effects of economies of scale are included separately for the combined cycle and the gasification systems. Costs analyses were based on today's values for commercial combined cycles, a 30 MWe biomass gasification plant and logistics costs for trash based on conditions for São Paulo state. Costs for transportation are also considered within São Paulo region, more specifically the Piracicaba region. Biomass logistics are expressed in constant values per ton; except for the transportation costs, which are related to the conversion system's capacity.

It should be kept in mind that the results presented were obtained though a generic approach for scaling up Combined Cycles. This gives an 'average picture'; in practice the performance of a specific project could deviate considerably from the values proposed and assumed in this study. In reality, combined cycles have discrete capacities according to the gas turbine that is used and steam cycles features (e.g. pressure levels) and that may lead to different costs that could differ substantially calculated by the model at this work in individual cases. The approach in this study merely gives an overall picture of the parameters that influence the performance of co-fired combined cycles, which is relevant as such to identify promising configurations for individual projects.

The use of biomass-derived gas in a co-fired scheme can enhance the use of biomass and allow a substantial decrease in COE. The calculated ranges for the COE dropped from very high today's costs for 100% biomass fired BIG-CC of about US$94/MWh at a 24MWe capacity, down to US$ 59MWh for 150MW of biomass power in a 50% natural gas co-fired plant. This cost reduction results from gains in efficiency and economies of scale up to a 300MWe co-fired plant. Furthermore, the natural gas addition avoids any de-rating that would occur with exclusive biomass derived fuel gas firing. The 50% share of biomass is the breakeven point for benefits associated with co-firing under the assumptions for the base scenario. When the natural gas share is increased further, prices for the biomass share start to rise again and eventually get higher than those for 100% biomass BIG-CC. This can be explained by the increasing specific capital costs of the biomass pre-treatment, gasification and gas cleaning equipment, at smaller scales.

When it is assumed that the costs for biomass collection are cut in half and natural gas prices increase by 50%, (which may not be unlikely on forseeable term) the COE from biomass can end up around US$40/MWh for the 50% share of biomass (150MWe) in a 300 MWe co-fired plant. This scenario showed no breakeven point for share of natural gas up to 70%. However, no benefits are observed for the smallest capacities (20-30MWe) as the shares vary from 30 to 70%. The assumed cost reduction is very likely to occur for trash as the costs used for this work are based on initial baling tests carried out for a short period of time and without optimization.

Natural gas is mostly an imported commodity that should be paid in dollars and a less strong variation is assumed, which seems to be reasonable in a mature nature gas market such as US market.

The mixture with natural gas might be necessary to increase the scale of the plants as there are strong indications that the gasification and cleaning systems are limited to a 300-400MWth capacity range for atmospheric equipment [3]. For the modelling, we assumed that further scale increases are possible, which may be unrealistic. For the results this does not matter much though; in fact, the best results are obtained at a capacity of 150 MWe or a 330 MWth biomass gasification plant, which is within the likely maximum scaling limits for the atmospheric gasification and gas cleaning systems.

BIG/CC systems may be scaled up to even larger capacities on longer term, but insights to what extent this is feasible for various biomass gasification technologies is limited so far, because little commercial experience exists. This aspect deserves further research (see also [27]). This study though, was focused on the short term, direct, atmospheric gasification technology and analysing the impacts of co-firing available combined cycles.

Sensitivity analysis performed for a 100MWe, 50% natural gas co-fired plant, show that the COE are most sensitive to the systems efficiency (highlighting the relevance of avoiding de-rating), the capital costs of the combined cycle plant and biomass gasification equipment and finally, the costs of trash (biomass fuel) delivered at the plant. The efficiency has been already substantially increased by co-firing biomass gas with natural gas at this capacity (from 40 to 45%), but further improvements can be achieved with gas turbine and overall system optimization and further operational experience on longer term. Substantial cost reductions are expected for biomass gasification equipment compared to the cost levels assumed for this analysis. Due to technological learning the (very high initial capital) costs of the biomass gasification part may even be cut in half, which could result in COE of around US$40/MWh for larger co-fired combined cycles.

Another advantage of co-firing is that it is also likely to dampen the risks of potential strong price fluctuations associated with power generation from natural gas, which in turn is very sensitive to natural gas price variation. A 40% increase on natural gas costs would lead to about 20% increase on energy costs for a 100MW (52% efficiency) combined cycle on natural gas, while the same increase would lead to a 5% average COE increase in a 50% co-fired scheme. This shows a considerable reduction on the plant sensitivity to natural gas price fluctuations.

The current Brazilian average natural gas supply prices are, however, very low ranging from US$ 28 to 32/MWh [26]. There are estimations that marginal costs of adding new units between 1998-2005 is approximately US$45/MWh, which is 50% higher than the current generation prices. This value is barely below the average COE for 50% co-fired plants (see figure 12). Considering the scenario with biomass price reduction, the average COE from co-fired plants are below this value for plant capacities larger than 150MWe (at 50% co-firing mode). More important, at this scenario with biomass costs reduction, COE from biomass in an integrated gasification co-fired plant are competitive. Co-firing is therefore a promising strategy to apply biomass as competitively as possible. This paper has provided insight in promising co-firing configurations and key factors that can improve the cost effectiveness further.

Further studies on co-firing should for sugar cane residues should enhance the insight on trash collection, scale limits for gasification and cleaning systems and extend the analysis to larger capacities, especially on pressurized systems. Costs reductions for longer term should also be considered.

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Capítulo 6

Conclusões e Recomendações

A tecnologia BIG-CC, de gaseificação de biomassa integrada a ciclos combinados, é a alternativa mais eficiente para a conversão de biomassa em eletricidade. Essa tecnologia se contrapõe à tecnologia tradicional de produção de energia elétrica em ciclos a vapor, opção que é de baixa eficiência e só pode ser viabilizada em pequena escala. O crescente interesse na utilização da biomassa, proveniente de plantações energéticas ou de resíduos, para a geração de eletricidade se justifica pelo seu potencial de redução das emissões de dióxido de carbono. A combustão da biomassa libera dióxido de carbono que foi absorvido no crescimento da planta, resultando assim em emissões neutras ou muito baixas. Além disso, a biomassa contém, em geral, baixo teor de enxofre. A utilização da biomassa para geração de eletricidade conta ainda com outros benefícios potenciais, tais como geração de empregos no campo e o aproveitamento de terras ociosas. A geração de empregos no campo pode minimizar o problema do êxodo rural nos países em desenvolvimento.

A tecnologia BIG-CC ainda não é comercial, seus custos iniciais ainda são elevados e a adaptação do ciclo de potência para o uso do gás de biomassa requer modificações nas turbinas a gás. Além disso, é necessário adotar estratégias de controle das turbinas a gás, que penalizam o desempenho de todo ciclo. Apesar do insucesso comercial de alguns projetos de demonstração da tecnologia, e da indefinição de outros, o interesse continua vivo. O sucesso do projeto de demonstração cuja unidade ora está em construção na Inglaterra será fundamental para a demonstração da tecnologia de gaseificação atmosférica, bem como para a redução de seus custos.

Este trabalho sugere o cofiring do gás de gaseificação da biomassa com gás natural como uma opção de curto prazo para a melhoria da performance técnica e econômica da tecnologia BIG-CC. No estudo, apenas a gaseificação atmosférica da biomassa foi considerada, pois a tecnologia está mais próxima de um estágio comercial e é a de menor custo inicial. Além disso, a limpeza dos gases pode ser mais facilmente efetuada na configuração considerada, uma vez que o gás é resfriado e passa por um lavador, em processo que retira grande parte dos contaminantes solúveis. O estudo da queima conjunta dos dois combustíveis foi desenvolvido para o Estado de São Paulo, tendo em vista a crescente disponibilidade de pontas e folhas com o advento do fim das queimadas. Outros fatores que definem o contexto favorável são a oferta crescente de gás natural, seu mercado ainda incipiente, a necessidade de expansão da capacidade de geração elétrica, os riscos associados às termelétricas a gás natural e as dificuldade enfrentadas pelos empreendedores que querem construir as novas térmicas a gás próximas dos centros de carga.

O foco deste trabalho foi posto na análise de uma alternativa que permite reduzir restrições tecnológicas e melhorar a viabilidade econômica da geração de eletricidade a partir da biomassa gaseificada. Demonstra-se que reduções dos custos de capital e ganhos de eficiência podem ser alcançados com o aumento da economia de escala dos sistemas de potência, o que é possível graças ao aporte de gás natural.

A análise feita se baseia na simulação termodinâmica de ciclos BIG-CC operando com diferentes percentuais de mistura combustível. Para que pudessem ser determinados e analisados os efeitos de escala, ciclos BIG-CC de diferentes capacidades foram definidos. Os ciclos se baseiam em configurações comerciais que podem produzir 30 MW, 100MW e 210 MW quando da queima de gás natural. Uma turbina aero-derivativa foi escolhida para o menor ciclo, enquanto as outras duas plantas têm por base turbinas industriais. A turbina aero-derivativa foi considerada devido a sua melhor eficiência.

A tecnologia de gaseificação atmosférica foi estudada para a utilização tanto do bagaço quanto das pontas e folhas da cana. No entanto, a avaliação econômica dos ciclos BIG-CC cofiring foi focalizada apenas na utilização das pontas e folhas. A justificativa para tal decisão está no fato de que no estudo foram consideradas apenas termelétricas fora da área física das usinas e, conforme demonstrado no Capítulo 2, uma maior disponibilidade de bagaço excedente irá requerer investimentos significativos nas usinas. De qualquer forma, muitas usinas em São Paulo têm porte (e biomassa) suficiente para que os sistemas cofiring estejam dentro das próprias usinas. Além disso, a decisão pela localização dependerá também de onde a biomassa das pontas e folhas estará disponível.

Os resultados deste trabalho foram distribuídos em três artigos científicos submetidos a revistas indexadas internacionais. O primeiro artigo, que compõe o terceiro capítulo da tese, apresenta as características do sistema BIG-CC, as hipóteses da modelagem, as características físicas e químicas do bagaço e da palha, e a análise de sua adequação para a gaseificação em sistemas de grande porte. Os resultados da simulação computacional correspondem às quatro estratégias de controle consideradas para queima de gás de baixo poder calorífico em turbinas a gás. Essas estratégias são inspiradas em trabalhos anteriores relacionados à gaseificação de carvão e permitem a operação das turbinas a gás sem que sua razão de compressão atinja níveis muito próximos do limite de *surge*. A base para comparação foi definida no caso hipotético em que nenhuma estratégia de controle seria necessária. É demonstrado que a aplicação do *de-rating*, que é a estratégia mais simples e barata para controle do surge, resulta em maiores perdas. As perdas em eficiência são menores quando a estratégia de controle adotada é a extração de ar do compressor. Por sua vez, a principal vantagem do *redesign* da turbina a gás é o ganho em potência, que pode ser inclusive 8% maior em relação à potência produzida sem a adoção de uma estratégia de controle. A eficiência nos dois casos é praticamente a mesma. O *redesign* é, no entanto, uma estratégia cara e só pode ser considerada no médio-longo prazos. Tanto no caso da extração de ar do compressor quanto no caso em que a turbina é redesenhada, a necessidade de se manter a temperatura do exaustão da HRSG acima de um limite (200°C) prejudicou a eficiência do ciclo.

O segundo artigo corresponde ao quarto capítulo e apresenta os aspectos técnicos do cofiring. O objetivo do trabalho foi avaliar o potencial associado às menores adaptações nas turbinas a gás e às melhorias no desempenho do ciclo. Os resultados da simulação demonstram que para percentuais entre 30 e 50% de gás natural em base energética na mistura não é necessário *de-rating* da turbina a gás. Para esse percentual de gás natural a eficiência do ciclo fica em torno de 95% daquela prevista para a mesma configuração quando da queima só de gás natural. Considerando a potência do ciclo, o *cofiring* produz um valor máximo para um conteúdo de gás natural um pouco maior, em torno de 35-55% em base energética. A máxima potência é até 10% maior do que aquela obtida com gás natural. Com a quantidade estimada de gás natural como capaz de evitar o *de-rating*, a mistura poderia ser queimada em turbinas com câmaras de combustão projetadas para o gás de carvão mineral, que é uma tecnologia já comercial. O *cofiring* poderia também reduzir o risco da propagação contrária da chama, que está associado a gases com conteúdo de hidrogênio muito alto, como é o caso do gás de biomassa. A mistura com gás natural reduz a concentração de hidrogênio, porém não foram obtidos resultados conclusivos quanto à obediência da concentração máxima permitida. Um ponto importante diz respeito às emissões de NO_x térmico, o que não deve ser problema para ciclos que utilizem apenas biomassa gaseificada, mas que aumentam com a inclusão de gás natural na mistura. Este é um aspecto importante tendo em vista as limitações para a utilização de sistemas *dry low NOx*.

O quinto capítulo descreve a análise econômica da alternativa *cofiring* quando consideradas economias de escala. Os resultados incluem os ganhos em eficiência relacionados ao aumento do poder calorífico da mistura e ao aumento de escala da instalação. Os efeitos de escala foram obtidos de um procedimento de modelagem. Economias de escala foram avaliadas e consideradas tanto à planta de ciclo combinado quanto ao sistema de gaseificação. As capacidades consideradas vão de 20 a 300 MW elétricos. A partir dos resultados deste modelo efetuou-se um estudo econômico com o intuito de se avaliar os benefícios da produção de eletricidade a partir da queima conjunta em um ciclo combinado integrado a um gaseificador (BIG-CC). A análise se baseia em um método de alocação de custos a fim de se identificar os custos da produção de eletricidade a partir da biomassa. Uma redução substancial no custo de eletricidade gerada é obtida com o *cofiring*. Esse custo pode ser reduzido de US$ 94 para US$ 59/MWh através da melhoria de eficiência e com as economias de escala. Considerada a biomassa os benefícios do *cofiring* apresentam um limite. A máxima redução de custos é obtida para uma mistura com 50% de gás natural em base energética. Coincidentemente, tal porcentagem resulta em uma capacidade máxima de 150 MW para a eletricidade gerada a partir da biomassa (considerando a capacidade máxima de 300 MW). Outros estudos avaliaram em cerca de 150 MW a capacidade ótima de sistemas BIG-CC operando exclusivamente com biomassa. Outra parte do estudo também considera um estudo de sensibilidade, avaliando-se os efeitos de uma possível redução nos custos da biomassa (no caso, pontas e folhas). Neste novo cenário o custo associado aos resíduos é reduzido à metade, enquanto o preço do gás natural sofre um aumento de 50%. Ainda sem considerar redução no custo de capital, o que é muito provável ainda no curto prazo, os custos para a produção de energia a partir de biomassa gaseificada podem cair até US$ 40/MWh, ficando bem próximos do custo marginal previsto para a expansão do sistema elétrico brasileiro.

Este trabalho apresenta as limitações típicas de estudos desenvolvidos sob um enfoque multidisciplinar. Tanto os aspectos técnicos quanto os econômicos do problema podem e devem ser explorados de maneira bem mais detalhada. Contudo, o objetivo do trabalho, de se identificar potenciais benefícios relacionados à opção *cofiring* na utilização da biomassa no Brasil, foi cumprido. O estudo demonstrou que com o *cofiring* há a possibilidade de redução de custos e de superação de barreiras tecnológicas associadas à tecnologia BIG-CC, que se encontra em desenvolvimento.

Este trabalho se baseia em modelos termodinâmicos e econômicos, buscando identificar tendências. Uma profunda avaliação técnica experimental é fundamental para o prosseguimento de estudos relacionados ao tema, envolvendo a combustão da mistura gasosa, as estratégias de controle e de operação, os efeitos do alto conteúdo de hidrogênio, os efeitos da temperatura de chama, as emissões de óxidos de nitrogênio, entre outros fatores. O estudo feito demonstra que o *cofiring* pode resultar em melhorias de desempenho termodinâmico e reduzir a necessidade de adaptação das turbinas a gás. Ambos fatores redundam em benefícios econômicos.

A simulação termodinâmica não foi feita de sorte a se explorar configurações otimizadas em função das diferentes composições da mistura combustível. Assim, as conclusões desse estudo poderiam ser ainda melhores em função dos possíveis ganhos de desempenho. As simplificações adotadas na modelagem não invalidam, no entanto, as principais conclusões do trabalho. Por exemplo, em estudos futuros devem ser consideradas configurações otimizadas para a geração de vapor nas caldeiras de recuperação, bem como seus efeitos no ciclo a vapor. Também deve ser melhor avaliado o processo de secagem, que impõe uma temperatura mínima para os gases de exaustão da HRSG, limitando o desempenho do ciclo a vapor.

Com respeito à análise econômica, existem limitações relacionadas aos modelos adotados e à estimativa de custos. O modelo genérico para o cálculo de eficiência e capacidade tem como base os resultados apresentados nos dois artigos técnicos e, assim, possui as mesmas limitações dos resultados da modelagem termodinâmica. Além disso, o modelo considera um contínuo em toda a faixa de capacidade, enquanto na realidade os ciclos comerciais têm capacidade discreta e obedecem a um "*trade-off*" entre custo e eficiência. Assim sendo, ciclos de capacidades menores podem ser dotados de características que os beneficiem, a ponto de serem mais eficientes que ciclos de maior porte. O custo da biomassa, que inclui coleta e transporte, depende de diversas variáveis, como o tipo de fardo, a eficiência e o custo da enfardadora, o tempo de secagem etc. Os valores adotados neste trabalho foram obtidos dos primeiros testes realizados pela COPERSUCAR e podem corresponder a uma sobre avaliação. A otimização do processo pode levar a melhorias significativas nos custos. Do ponto de vista da disponibilidade de biomassa, o desenvolvimento de tecnologias adequadas à inclinação de solo brasileiro também é fundamental para a disseminação da colheita de cana crua. Estes aspectos merecem avaliações mais profundas e estão além do escopo deste trabalho.

Finalmente, cabe observar que a opção *cofiring* analisada neste trabalho não é a única possível, e talvez até seja não tão adequada considerado o estágio atual de desenvolvimento da tecnologia BIG-CC. Estudos são necessários para que as demais opções tecnológicas sejam consideradas, e para que todas as alternativas sejam também avaliadas quando da consideração das plantas de geração dentro das próprias usinas.

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Anexo I

$$T_{02} = \left(\left(\frac{(P_{02}/P_{01})^k + 1}{\eta_C} \right) \times T_{01} \right) \qquad Eq.2$$

Sendo que:

η_c é a eficiência isoentrópica do compressor

T_{01} é a temperatura do ar à entrada do compressor

T_{02} é a temperatura do ar à saída do compressor

$$m_{fuel} = \frac{(m_{comp} \times (f_{cool} - m_{blast}) \times Cp\ (T_{max} - T_{02})}{LHV \times \eta_{comb} - Cp \times (T\max - T_{01})} \qquad Eq.3$$

Sendo:

m_{comp} é o fluxo mássico de ar à entrada do compressor (kg/s)

f_{cool} é a fração de ar de resfriamento

m_{blast} é fluxo de ar "blasted" do compressor, no caso da estratégia de controle que corresponde à extração de ar (kg/s)

T_{max} é a temperatura máxima dos gases de combustão (K)

LHV é o poder calorífico inferior do combustível (kJ/kg)

Cp é o calor específico dos gases de combustão (kJ/kg.K)

2.3 Ar de resfriamento

No modelo supõem-se que metade do ar de resfriamento das palhetas é misturado ao fluxo dos gases de combustão à saída co combustor. A temperatura da mistura pode ser calculada pela equação 4., sendo que todas as variáveis já foram previamente especificadas.

$$T_{03} = T_{01} + \frac{(m_{gases} \times Cp \times (T\max - T_{01}) + (m_{comp} \times (1/2) f_{cool}) \times Cp(T_{02} - T_{01})}{(m_{gases}) \times Cp} \qquad Eq.4$$

O fluxo de gases m $_{gases}$ após a diluição é calculado pela equação 5:

$$m_{gases} = \left(m_{comp}(1 + (1/2)f_{cool}) - mblast + m_{fuel}\right) \qquad Eq.5$$

2.4 Expansor

A rimeira avaliação da temperatura dos gases na exaustão do expansor corresponde à hipótese de que a expansão seja isontrópica, para a qual emprega-se a equação 6:

$$T_{04} = \frac{T_{03}}{\left(\frac{P_{03}}{P_{04}}\right)^{((1-k)/k)}} \qquad Eq.6$$

Sendo

T_{04} é a temperatura dos gases à saída do expansor no caso da expansão isoentrópica

P_{03} é a pressão dos gases à entrada do expansor

P_{04} é a pressão dos gases à saída do expansor

E a temperatura real na exaustão da turbina a gás é estimada pela equação 7.

$$T'_{04} = T_{03} - \eta_t\left(T_{03} - T_{04}\right) \qquad Eq.7$$

Sendo T'$_{04}$ a temperatura na exaustão. Como na modelagem considera-se que o fluxo restante do ar de resfriamento das palhetas é introduzido ao fluxo de gases imediatamente antes da exaustão, a estimativa da temperatura real de exaustão (T_{exaust}) é feita pela equação 8, abaixo:

$$T_{exaust} = \frac{T_{atm} + (m_{gases} \times Cp\,(T'_{04} - T_{atm}) + (m_{comp} \times f_{cool} / 2) \times Cp \times (T_{02} - T_{atm})}{\left(m_{gases} + m_{comp} \times f_{cool} / 2\right) \times Cp} \qquad Eq.8$$

Anexo II

1. Outros parâmetros adotados na simulação de turbinas a gás:

	Aero-derivativa	Média	Grande
Fluxo mássico de ar (kg/s)	68,17	193	409
Eficiência do Combustor	0,996	0,999	0,996
Perda de carga no combustor	0,035dp/p	0,03dp/p	0,035dp/p
Eficiência do alternador	0,99	0,985	0,9921
Perda de carga na entrada (mbar)	10	10	10
Perda de carga na saída (mbar)	57	57	57

2. Algumas equações empregadas no procedimento de modelagem das turbinas a gás

2.1 Compressor

$$\eta_{comp} = \left(\left((P_{02}/P_{01})^{K} - 1 \right) \Big/ (P_{02}/P_{01})^{\frac{K}{\eta_p}} \right) - 1 \qquad Eq\ 1$$

Sendo que:

η_{comp} é a eficiência isoentrópica do compressor

P_{02} é a pressão total do ar à saída do compressor

P_{01} é a pressão total do ar à entrada do compressor

$k = [C_p/(C_p - R)]$

η_p é a eficiência politrópica do compressor nas condições de projeto

2.2.Câmara de combustão

No modelo de simulação o consumo de combustível é estimado em função da temperatura dos gases à saída, que é um valor pré especificado. No balanço de energia feito na câmara de combustão a temperatura do ar é estimada pela equação 2. O fluxo de combustível em si é estimado pela equação 3.

POSSIBILITIES AND CONSTRAINTS FOR CO-FIRED (SUGAR-CANE RESIDUES +NATURAL GAS) CHP PLANTS IN THE STATE OF SÃO PAULO, BRAZIL

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ABSTRACT: This work investigates opportunities for co-fired BIG-CC integrated with a sugar mill. The basic idea is that on site residues (biomass +trash) are not enough for the system to operate all year round. Possibilities for natural gas use during cane off-season as well as residues for other mills are studied. The net availability could reach about 300 PJ per year in Sao Paulo within scenarios considered. Some characteristics in Brazilian power sector might lead to some NG surplus during sugar cane off-season. Results compare the co-firing option to BIG-CC plants running on biomass only. Two strategies were considered to investigate the system performance system when it operates with gas from biomass.: de-rating and gas turbine retrofit. There is a large potential (1.2-3.6 GW) for BIG-CC systems running on biomass only. However, the residues will come available only if prices are worthwhile. In case biomass has a price higher than US$8/ton and de-rating is applied, co-firing showed to be less costly within the options considered. This can lead to 512MW of biomass energy delivered to the grid during the season. Results are compared to those when the gas from biomass is used in a retrofitted turbine. In this case, systems with biomass only would be less costly than co-fired for any of adopted prices for biomass and NG. Nevertheless, this option is difficult to accomplish in a short term for it is more costly and complex.

1. INTRODUCTION

Biomass already plays an important role in the state of Sao Paulo. The share of biomass in the energy consumption is 15%. Bagasse represents 70% of the total biomass consumed. Bagasse is used as a fuel in sugar mills for on site power and steam demand. Current conversion facilities have very low conversion efficiency though: the average efficiency for the CHP plants is around 30%[1]. Improvements on the industrial process and on CHP plants could enhance the utilisation of bagasse considerably. Additional biomass availability is expected with green cane harvesting. The cane trash, which now burned on the fields, will be then available. Trash consists of leaves and tops of sugar cane plant. This future availability is related to regulation changes and to a move towards mechanisation. On-site residues are not enough to operate the proposed BIG-CC system all year round, therefore natural gas is proposed as a complementary fuel for off-season operation. This option is compared to the use of biomass (trash + bagasse) all year long. The idea emerges from the fact that natural gas will be available, possibly at lower prices during rainy periods. This is related to the higher availability of hydropower during this season. Consequently, part of the thermal plants will not even operate or operate with a low capacity factor. Therefore, part of this natural gas could be used in CHP plants to ensure the capacity utilisation.

2. RESIDUES AVAILABILITY

Two types of residues are analysed within this work: Bagasse and trash. Bagasse is obtained after the juice extraction in the sugar-cane mill and is constituted mainly of fibres and water. This residue is widely used in the sector. Trash is the combination of dry/green leaves and tops from the sugar-cane plant. Trash is currently burnt in the field before harvesting. For environmental reasons, this practice has been questioned leading to legal measures in the State of Sao Paulo. A possible shift towards green cane harvesting will make large quantities of biomass available In case investments to increase the efficiency in sugar cane factories are made, the bagasse availability can be considerably increased This will depend on efforts to lower the steam demand and improve CHP plant efficiency.

2.1 The bagasse utilisation

Bagasse production varies from 240 to 280kg per ton of crushed cane. The bagasse is mainly consumed in the sugar and alcohol factories where it is produced. The sector produces some excess, being the current percentage of bagasse not used in the sugar mill about 10% of total (1). This bagasse is either burned as disposal or sold to food & beverage industries. This industrial market is presently threatened by natural gas though. Regarding the industrial sector in the state of Sao Paulo, bagasse is the main fuel since 94. In sugar mills, the bagasse is used as fuel for the boilers that provide steam for the process, to drive the mills and for the electricity production. Steam is produced to match process requirements and the power production follows the steam demand. The CHP systems are based on low-pressure boilers and backpressure steam turbines. The CHP plants operate during the harvest only and use bagasse as a fuel. There is no CEST (systems based on condensing steam cycle with extraction) cogeneration system operating in the sugar-alcohol sector in Sao Paulo. Most of factories are self-sufficient in energy. There are few contracts for exporting electricity, summing 26 MW of power during the harvesting (2) This is explained by the very low price paid for electricity surplus: 20-25US$.

2.2. Bagasse availability

Whether there can be a surplus of bagasse depends on steam requirements in the sugar and alcohol factories, the efficiency of cogeneration system and the use of the excess bagasse

[1] First law, dry basis

outside the sugar mills. To estimate the potential increment on bagasse availability over the next ten years, 2 scenarios are considered. Scenarios are conservative: power export was not considered and improvements on the industrial process are yet small. Co-generation systems are based on back-pressure turbines and operate during harvesting only. The reference scenario corresponds to the current average sugar-alcohol factory in the state of Sao Paulo. Some factories can differ a lot since data deviation is high (3). Scenario I considers the replacement of CHP system keeping the same pressure for the boilers. The operational efficiencies for the new equipment are 0.78 and 0.70 for the boiler and turbine, respectively. The steam requirement is slightly reduced as a consequence of efficiency increase on power production. As for the back-pressure system the steam demand defines the power production, if the steam demand is not reduced there would be surplus power. A compromise between power production and steam requirements keeps the self-sufficiency on power without surplus. Scenario II considers the reduction of steam consumption to a feasible level considering characteristics of current equipment (3). The boiler pressure is increased and consequently the efficiencies (0.82 for the boiler and 0.8 for the steam turbine). This increase is necessary to cope with the steam reduction and yet keeps self-sufficiency. These scenarios give an idea of how bagasse availability can be increased in the next ten years with low investments. Some assumptions and results are presented in table I.

Table I. Scenarios for sugar-alcohol factories in Sao Paulo

	Reference	I	II
Process Steam (kg/tc)	500	485	420
Steam pressure (MPa)	2.1	2.1	3.1
Steam temperature (°C)	280	280	400
Boiler efficiency	0.70	0.74	0.76
Power turbine efficiency	0.66	0.71	0.73
kg of steam /kg of bagasse	2.09	2.21	2.27
kg steam /kWh (electrical)	14.4	13.4	7.9
Excess bagasse (%)	10	22	34
Bagasse availability(PJ)		**97**	**153**

Assumptions: mechanical and electrical requirements: 15 kWh and 12 kWh per ton of crushed cane, respectively. Bagasse: 260 kg/ton of crushed cane, mill efficiency: 0.43, discharge pressure: 0.25 MPa.

2.3 Trash availability

Trash availability depends on the elimination of pre-burned harvesting, practice that facilitates the manual harvesting. Green cane harvesting is much harder and harmful for the labour. Therefore, the costs for manual cutting of cane exceeds R$[2] 6.00/t. Today's cost for manual harvesting and loading of "burned cane" is around R$ 4.00/t (5). Legislation in the state of Sao Paulo requires pre-harvest burning to be extinguished till 2005 in regions with a smooth topography and by 2012 in areas with a more difficult topography (4). The reason for this enforcement is the impact on population health and amenity. Green cane harvesting depends on mechanical harvesting and the shift to mechanisation is inexorable due to economic reasons. For green cane mechanical harvesting, there are some indications of costs below R$ 3.00/t (4). However, there are still some constraints for the implementation. The main technical constraint is the topography. The design of present harvester limits its utilisation to 45% of the planted area in Brazil (4). The topography in Sao Paulo varies a lot but in general is more favourable. An assumption that 60% of the planted area is suitable for mechanisation was made. Mechanisation can also bring social impacts due to the displacement of labour that works on manual harvesting. High investment costs would be an additional barrier for implementation

2.4 Trash gross and net availability

Trash is the sum of top and leaves of sugar-cane and represents around 25-30% of the total energy in the plant. In case current practice of burning is eliminated, large quantities of trash will be available, estimates vary from 0.10 to 0.18 tons dry tons/clean stalks for commercial cane. Taking the 97/98 harvest, around 180 million tons of sugar cane were crushed in the sugar factories in Sao Paulo corresponding to a gross availability of 27 Mt (dry basis) with energy content around 485PJ. This trash is not totally recoverable though. Part of this amount is left on the field for agronomic reasons; recommended shares vary between 50% to 67 % (5) depending on local agronomic conditions. The trash left on site as weed suppressant leads to the reduction in the use of herbicides. According to experiments carried out within GEF project (5), when 2/3 of the total amount of trash is left on the soil weed control reaches levels of efficiency higher than 90%. This efficiency is comparable to most of herbicides treatments employed in sugar-cane crop (5) Trash availability is presented in figure 1. The calculated availability is compared to that in case mechanisation is applied to 90% of planted areas. This is technologically feasible in case other machinery is used in the planted area (5)

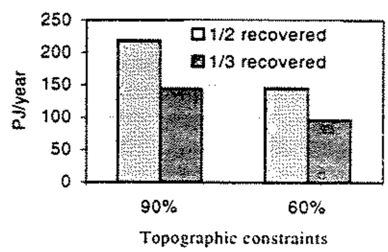

Figure 1. Trash Availability

3 NATURAL GAS AVAILABILITY

The idea of combining biomass and NG as fuels seasonally for a BIG-CC plant emerges from natural gas availability, which is related to:

- A newly built gas pipeline that crosses some main sugarcane production areas (18 million Nm^3/day is contracted)
- During off cane season a larger availability of natural gas is expected, possibly at lower prices. This extra amount of NG will come from some power plants operating as thermal complementation.

3.1 Thermal complementation

A typical hydropower profile over four years is presented in figure 2. The energy flow is the total amount of average power that could be obtained from the water available. In rainy periods the amount is much higher than the firm capacity (see figure 2). The amount above the capacity is

[2] Conversion 1US$ = 1.8 R$

partially stored to cover the supply during dry season or for subsequent years. The remaining part can be eventually used but is mostly spilled. A share of this energy should be used combined with CC power plants running on NG in coming years. An additional 1 GW to the firm capacity so-called hydrothermal capacity represents this share. Therefore, during the rainy season the extra hydropower will displace the thermal capacity and thus natural gas. Estimation of this extra hydropower varies between 2.5-3GW. Within this work, 1 GW was assumed as surplus hydropower.

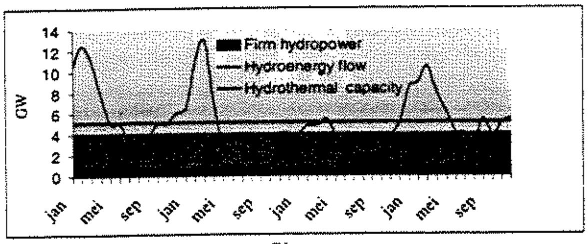

Figure 2. Hydropower profile

4. CASE STUDY

A BIG-CC integrated to a typical sugar-cane mill operates during the season as a CHP plant that provides steam for the process. In the off-season it operates as a power plant. The co-firing option is compared with a system fuelled with biomass only (from other mills). The BIG-CC system is based on atmospheric gasification and the LM2500 gas turbine. Power is exported to the grid.

4.1 System description

The system is similar to that described in (8). The only difference is that steam is extracted from the steam turbine at 0.25 MPa during cane harvest season to fulfil the factory steam requirements.

4.2 Performance calculations

The system is simulated by a code described by Walter (7). In performance calculations, de-rating is used as a strategy to allow the use of the gas from biomass in a gas turbine originally designed to burn natural gas. De-rating is the reduction of the combustion temperature. This is necessary since a much larger volume is led trough the gas turbine. (10 times compared to NG). De-rating reduces the fuel flow and the compressor pressure ratio to safe limits with penalties for the cycle efficiency and output power. The performance is compared to the case when no-de-rating is applied which would require a turbine retrofit. The basic change in this case would be the increase in the turbine expander area, but this is difficult to accomplish in short term for it is more costly and complex. De-rating is probably the worst control system from the efficiency point of view, but it can also be the simplest to be applied (7). Table II presents fuels ultimate analysis and syngas composition.

4.3 The sugar mill

An average sugar mill was considered for the case study. The factory operates 190 days per year crushing about 800 thousand tons of cane. It was assumed that in case a BIG-CC would be installed, the steam consumption should be lowered to 300kg per ton of crushed cane. This level is achievable with techniques of energy conservation (1). Considering the bagasse available in the factory (260 kg/ton of cane) and the trash (30% of the gross availability) the system can operate the whole harvesting period. The study also compares the option of burning biomass only. General figures and some results are presented in table III.

Table II. Ultimate analysis and syngas composition

% weight – dry basis	Bagasse (7)	Trash (6)	Syngas	Raw %mol	Clean %mol
C	46.3	45.3	H_2	14.99	16.69
O	43.3	42.4	CO	17.95	19.98
H	6.4	6.3	CO_2	9.42	10.49
N	-	0.78	CH_4	2.36	2.63
			C_6H_6	0.30	0.33
			H_2O	11.75	3.24
Ash	4.0	5.3	N_2	41.9	46.64
			Others	1.43	------
Moisture	50%	27%			
LHV[MJ/kg]	17.5	17.6	5.16		

Table III. System characteristics

	Season (biomass)	Off season (NG)	Off season -(Biomass)
Crushed sugar cane (tons)	800.000	0	0
Season (days)	190	175	175
Steam demand (kg/tc)	300	0	0
LM2500 + Boiler +ST	2.	2	2
Operation mode	CHP	Power plant	Power plant
Biomass(kg/s) (de-rating)	8.6	0	8.6
Biomass(kg/s) (retrofit))	10.8	0	10.8
NG (kg/s)	0	1.36	0
Surplus power (MW) (de-rating)	37	58	48
Surplus power(MW)-(retrofit)	57	0	70

4.4 Cost analysis

An evaluation on costs for electricity production with seasonal combination of Biomass and NG was performed. Costs were compared to a system burning biomass all year long[3], The biomass price (US$6.8/ton) is a weight average of bagasse and trash Assumed price for bagasse is US$ 3 US$/ton and first estimation for trash costs taken from GEF project (US$19.8) (5). Prices for NG are taken from values defined for power production (US$0.08/$Nm^3$). The obtained revenue with the investment is solely for the power sold to the grid.

5. RESULTS

5.1 Cycle performance

The applied de-rating (about 150° C of temperature drop) leads to a dramatic reduction in the overall cycle efficiency. Compared to natural gas CC, the penalty on the overall power

[3] 5^{th} commercial plant(US$ 2.716/kW),O&M (US$ 4/MWh and 6/MWh for off season and season operation, respectively). 30-year equipment,12% pre-tax discount rate , capacity factor:0.8

plant efficiency is about 20%. When syngas is burned but no de-rating is applied, the penalty is reduced (See table IV). In this case that requires a turbine retrofit, there are considerable gains in power compared to NG (5MW). With de-rating there is an excess of about 10% of biomass during the season. Without de-rating a small share of biomass should be imported (15%) during the season.

Table IV. Results from thermodynamics simulation

Fuel	Strategy	Operation	Cycle performance		Steam (kg/s)
			Power (MW)	η_c	
Syngas	De-rating	Power plant	24	0.36	
Syngas	retrofit	Power plant	34	0.41	
Syngas	De-rating	CHP	22	0.32	5.9
Syngas	retrofit	CHP	31	0.37	
NG			29	0.44	

5.2 Costs

It can be seen in figure 3 that de-rating has a strong impact on electricity costs compared to the option without de-rating (US$18-23/MWh). This is mainly due to the increment in power in case no de-rating is applied. When de-rating is considered, a seasonal co-firing can be more cost-effective for costs of biomass higher than US$8.00. If no-de-rating is applied, co-firing is always more costly for the fuel price range considered (see lines for retrofit in figure 3).

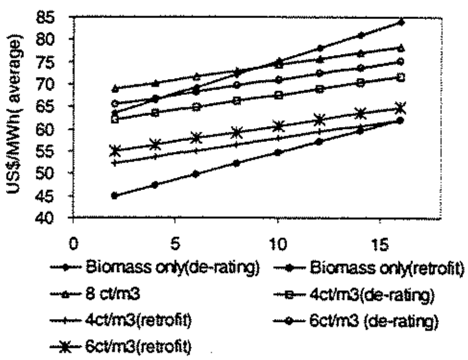

Figure 3. Electricity costs variation over biomass and NG prices

5.3 Potential

To calculate the co-firing potential in state of Sao Paulo the basic assumption is that a thermal capacity of 1 GW would complement the surplus hydropower capacity. The increase in power capacity with BIG-CC combined with hydropower and NG is shown in fig.4. The presented capacity is achieved with 14 systems like the proposed one. Moreover, 24 systems operating on gas turbine de-rating (1.2GW) could run on biomass only if half of the surplus bagasse predicted in scenario I would be available while 38 (1.8 GW) could operate with the excess bagasse estimated in scenario II. This capacity could double if trash is considered.

6. CONCLUSIONS

Co-firing led to some reduction on electricity costs compared to the alternative in which biomass is used all year round and gas turbine de-rating is applied.

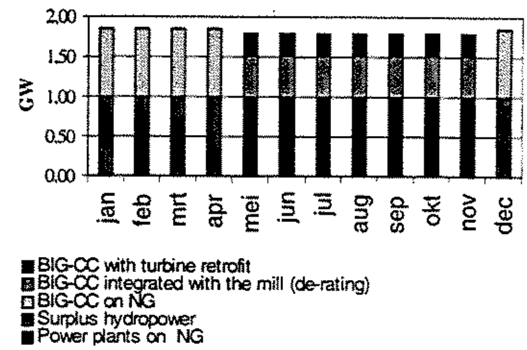

Figure 4. Co-firing in a supply profile

However, prices are still far from competitive in Brazilian current scenario with electricity prices between U$ 20-25/MWh. The combined use of natural gas is justified to optimise two sources of renewable energy (biomass and hydroelectricity) having the surplus hydroelectricity no costs. A combined use with NG could allow 512MW of biomass power to be delivered to the grid during dry season Further studies should analyse the average costs for the whole system (biomass + NG + hydropower). Concerning a better use of biomass resources, in case the estimated availability can be accomplished, the potential for BIG-CC is much higher (1.2-1.8) GW. However, this biomass will come available only if prices are high enough. This lead to a considerable increase in the electricity costs when de-rating is used (see figure3). When no de-rating is applied (turbine retrofit) biomass is a more cost-effective than any co-firing option considered. In fact, the costs drop dramatically. However, first commercial systems are more likely to use adapted turbine instead of retrofitted. Another possibility to deal with gas turbine de-rating drawbacks is to use a share of natural gas mixed to the syngas, which can partially offset efficiency penalties (8).

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