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# Analyse de la production d'électricité dans les pays producteurs de pétrole

Arash Farnoosh

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# THÈSE

Pour obtenir le grade de  
Docteur

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Spécialité : Sciences Economiques

Présentée par **Arash FARNOOSH**

**POWER GENERATION ANALYSIS IN OIL  
PRODUCING COUNTRIES  
(ANALYSE DE LA PRODUCTION  
D'ELECTRICITE DANS LES PAYS  
PRODUCTEURS DE PETROLE)**

**Soutenue le 17/03/2016 devant le jury composé de**

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*« L'université de Montpellier n'entend donner aucune approbation, ni improbation aux opinions émises dans cette thèse. Ces opinions doivent être considérées comme propres à leur auteur ».*

*“Every individual endeavours to employ his capital so that its produce may be of greatest value. He generally neither intends to promote the public interest, nor knows how much he is promoting it. He intends only his own security, only his own gain. And he is in this led by an invisible hand to promote an end which was no part of his intention. By pursuing his own interest he frequently promotes that of society more effectually than when he really intends to promote it.”*

**Adam Smith**

*The Wealth of Nations (1776)*

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## **Abstract**

National power generation mix composition is based on the ranking (merit-order) of the various means of production from their marginal cost of electricity generation. Thus, significant reserves of hydrocarbons in oil-producing countries favoured the abusive use of oil or natural gas in the electricity mix. The purpose of this research is to analyze the power generation mix of these countries by constructing an optimal electricity mix based on the rational use (from an economic point of view) of various electricity production means.

In this work, we assess the current and future situation of electricity production in Saudi Arabia, Egypt and Iran, thanks to linear, dynamic and statistical modeling efforts. Thereafter, we will conduct sensitivity analysis to measure the optimality and efficiency of electricity generation by taking into account the integration of alternative non-fossil-fuel based resources.

**Keywords:** Power Generation, Oil & Gas Resources, Optimal Electricity Generation Means, Economic Rent, Renewable Energies, Nuclear Energy.

## **Résumé**

La composition des parcs électriques nationaux est basée sur le classement des différents moyens de production par rapport à leur coût marginal de génération d'électricité. Ainsi, les réserves considérables d'hydrocarbure dans les pays producteurs de pétrole ont favorisé l'usage abusif du pétrole ou du gaz naturel dans le parc de production d'électricité. L'objectif de ce travail de recherche est d'analyser des parcs de production pour ces pays producteurs en construisant le parc optimal d'électricité concernant l'usage rationnel (du point de vue économique) des différents moyens de génération d'électricité.

Dans ce travail, nous évaluons la situation actuelle et future de la production d'électricité en Arabie Saoudite, en Egypte et en Iran grâce à plusieurs approches de modélisation : linéaire, dynamique et statistique. Ensuite, nous allons mener une analyse de sensibilité afin d'évaluer l'optimalité et l'efficacité de la production d'électricité en tenant compte de l'intégration des autres ressources alternatives non-carbonées.

**Mots-clés:** Production d'Electricité, Ressources d'Hydrocarbure, Parc optimal d'électricité, Rente Economique, Energies Renouvelables, Energie Nucléaire.

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## Introduction Générale

Suite à l'émergence de l'industrie électrique dans de nombreux pays producteurs de pétrole et de gaz naturel, les combustibles fossiles sont devenus la principale source de production d'électricité en raison de leur abondance et de leur disponibilité.

Dans la quasi-totalité des pays producteurs d'hydrocarbures, le secteur électrique s'est développé sous un système monopolistique principalement géré par l'administration publique et les Etats. L'émergence de la Saudi Electricity Company (SEC), l'Egyptian Electricity Holding Company (EEHC) et de l'Iran Power Generation & Transmission Company (TAVANIR) respectivement en Arabie Saoudite, en Egypte et en Iran, qui détiennent et gèrent la quasi-totalité de la production, transmission et distribution d'électricité nationale, sont des exemples révélateurs de l'implication des pouvoirs publics dans ce secteur.

Même après la décision de ces pays de s'orienter vers la privatisation et une industrie électrique soumise à davantage de concurrence, les combustibles fossiles sont restés les principales sources d'électricité. Ceci s'explique simplement par de très faibles prix domestiques du pétrole et du gaz naturel ainsi que d'énormes subventions accordées par le gouvernement, même aux producteurs privés d'électricité. Cette pratique a été progressivement arrêtée en raison de la volonté des gouvernements d'une gestion plus rationnelle de leurs ressources naturelles. Les prix élevés du pétrole et du gaz naturel (bien sûr indexés sur le pétrole brut) observés dans les marchés internationaux, spécialement après deux chocs pétroliers successifs, ont beaucoup contribué à cette philosophie de la rationalisation des ressources naturelles. Des prix élevés des matières premières énergétiques sur le marché international signifient plus de possibilités d'exportation et par conséquent une moindre incitation à perdre le bénéfice de ces précieuses ressources dans des processus inefficaces de production d'électricité domestique. Si les prix sur les marchés internationaux ont représenté une incitation, le progrès technologique fût également un facteur déterminant. Ce phénomène se traduit dans le temps par une courbe d'apprentissage décroissante des coûts de production des diverses technologies renouvelables et en conséquence la réduction de leur coût et ainsi les centrales à combustibles fossiles ont été de plus en plus considérées comme des unités de production coûteuses et inefficaces.

Evidemment, les analyses et perspectives économiques et financières constituent les moteurs les plus importants derrière la décarbonisation du parc de production électrique des pays producteurs de pétrole et de gaz, mais ils ne sont pas les seuls. Les préoccupations environnementales et des décisions politiques jouent elles aussi un rôle très important. Les facteurs environnementaux globaux (émissions de gaz à effet de serre et réchauffement climatique) et ceux plus localisés (particules en suspension dangereuses, NO<sub>x</sub> et SO<sub>x</sub>), sont tous deux devenus des sujets d'importance parmi les groupes politiques et les responsables gouvernementaux.

En outre, l'action politique et la philosophie économique sous-jacente constituent un facteur essentiel, étroitement axé sur des questions idéologiques, et particulièrement présent dans de nombreux pays producteurs d'hydrocarbures situés dans la région MENA (Moyen-Orient et Afrique du Nord). Par exemple, l'idée que les ressources nationales, y compris le pétrole et le gaz naturel, sont données par la puissance divine et dont la population locale doit bénéficier gratuitement. Ou peut-être est-il préférable de dire « à peu près gratuitement », avec un producteur qui peut tout au plus récupérer ses coûts de production. Cette ligne de pensée fût l'idée principale derrière la création et la promotion des subventions aux énergies fossiles, dès la découverte et le début de la production des combustibles fossiles dans les pays de la région MENA.

Cependant, depuis les années 1980, davantage de débats ont été menés parmi les décideurs politiques de ces pays sur l'utilisation optimale et par conséquent la meilleure répartition de ces richesses naturelles au sein de la population. Et c'est de par cette philosophie politique que la tendance à la décarbonisation du parc électrique national s'est soudainement accélérée. Quoi qu'il en soit, d'autres discussions et analyses sur ces questions idéologiques sont hors de la portée de cette étude et nous laissons aux sociologues, politologues et autres experts en philosophie économique le soin de répondre à ces problématiques. Dans ce travail, nous nous concentrons principalement sur l'analyse économique de la décarbonisation du parc électrique et dans notre approche, nous essayons autant que faire se peut de privilégier une analyse plus positive que normative. Cependant, dans chaque chapitre, après avoir observé les résultats obtenus de la modélisation économique, nous proposons quelques suggestions sur la politique économique optimale qui pourrait apporter davantage de bénéfices économiques pour les portefeuilles nationaux.

Dans ce but, nous avons choisi trois pays de la région MENA: l'Arabie Saoudite, l'Egypte et l'Iran. D'un côté, ces pays sont très semblables de par le fait qu'ils sont tous trois producteurs de pétrole et de gaz naturel, et qu'ils ont à peu près les mêmes structures que celles du secteur électrique. Ils recourent en large partie au pétrole et au gaz naturel pour la production d'électricité et ces ressources fossiles sont fortement subventionnées. A différents degrés, ils ont tous commencé le processus de transition vers un marché ouvert à la concurrence. Mais le système de la prise de décision via une planification centralisée est toujours omniprésent. En revanche, il existe de nombreuses différences entre eux en termes de politiques énergétiques, situations géopolitiques et géographiques, structure du parc électrique, ressources naturelles et humaines ainsi que de structure économique et institutionnelle.

Pour chaque pays une méthodologie de modélisation économique adaptée a été utilisée. Les modèles sont construits selon les spécificités de la structure du parc électrique de chaque cas. Dans le premier chapitre nous avons modélisé le parc national de production d'électricité de l'Arabie Saoudite. L'approche de la minimisation des coûts totaux de la production a été examinée dans le cadre de la Programmation linéaire (LP). Dans la littérature, nous pouvons trouver de nombreux exemples tels que Xydis & Koroneos (2012) et Chang et Li (2013) qui ont appliqué des méthodes de LP afin d'analyser et optimiser les futurs mix électriques de certains pays d'Asie. Ce qui est nouveau dans notre approche c'est l'utilisation de la méthode de programmation linéaire multi-étapes. Dans ce cas, nous avons construit trois modèles d'optimisation respectivement pour le parc national d'électricité du pays à court, moyen et long terme. En d'autres termes, nous effectuons une capture instantanée du mix électrique Saoudien actuel et futur. La structure des futurs mix électriques est construite sur la base des annonces des régulateurs du marché électrique en Arabie Saoudite en termes d'options d'investissement dans le secteur énergétique du pays. Compte tenu du caractère centralisé de la planification de l'industrie électrique en Arabie Saoudite, cette méthode semble être l'un des moyens les plus adaptés et fiables pour traiter la question suivante: Est-il dans l'intérêt de l'Arabie Saoudite de continuer à promouvoir l'intégration des énergies non-fossiles dans son système de production d'électricité ? Si oui, quels seraient les avantages économiques tangibles/quantifiables de cette action ?

En premier lieu, une analyse détaillée du parc national de la production d'électricité est réalisée. Nous étudions ensuite le potentiel de différentes sources d'électricité pour l'Arabie Saoudite, tant sur le plan économique que technologique. Enfin, le modèle détaillé est

présenté avec les résultats obtenus pour différents scénarios. Les informations concernant la politique de la tarification de l'électricité en Arabie Saoudite sont également fournies de manière à apporter de nouveaux éléments de réflexion visant à atteindre l'optimalité dans le système de production d'électricité.

Dans le chapitre II, nous examinons le cas du parc électrique Egyptien. Contrairement à l'Arabie Saoudite, cette fois, nous adoptons une approche de modélisation dynamique. Nous utilisons un modèle de programmation linéaire dynamique de manière à être en mesure de révéler un processus d'investissement plus lisse durant la période étudiée. La principale raison justifiant cette façon dynamique d'analyser l'investissement est le fait que l'environnement actuel d'investissement dans ce pays est très incertain. Après le printemps arabe et le retrait de Mr. Mobarak du pouvoir, le secteur électrique fait face à une grande incertitude en termes de prix, de planification, de gestion et bien sûr d'investissement. Dans ces circonstances, nous avons préféré utiliser un modèle dynamique avec des intervalles de temps plus rapprochés que ceux d'un modèle statique avec de grands décalages. Une analyse de sensibilité sur divers paramètres du modèle (comme le taux d'actualisation, par exemple) a été réalisée afin de mieux prendre en compte le caractère incertain du secteur électrique Egyptien et son impact sur les décisions d'investissement.

Cependant, les autorités Egyptiennes ont annoncé explicitement leurs préoccupations concernant les questions environnementales et la réduction de la pollution. Par conséquent, l'analyse de sensibilité sur le prix du CO<sub>2</sub> est également effectuée pour révéler l'impact de la variation des prix sur les tendances de l'investissement. Les résultats illustrent clairement l'intérêt de l'investissement dans les technologies non-fossiles à des prix élevés du CO<sub>2</sub>, en particulier accompagnés de taux d'actualisation faibles ou modérés. Tout le processus de modélisation pour le parc électrique Egyptien est effectué sous l'hypothèse d'une intégration des énergies renouvelables dans le mix électrique national à hauteur de 20%, annoncé par les autorités gouvernementales. Les coûts des unités de secours (*back-up*) ont également été mis en œuvre en conséquence dans le modèle, calculés par rapport aux propriétés techniques du mix de production Egyptien.

Enfin, dans le chapitre III, nous avons traité le cas du secteur électrique en Iran. Tenant compte de la tendance très forte vers la privatisation et la libre concurrence du secteur électrique en Iran (récemment, le gouvernement a même établi une bourse entièrement dédiée à l'électricité), nous avons adopté une approche totalement différente dans notre processus de

modélisation. Nous avons recouru à la Théorie moderne du portefeuille de Markowitz afin d'analyser le secteur électrique Iranien. Dans la littérature (soigneusement élaboré dans le chapitre associé), ces modèles sont considérés comme très puissants dans l'évaluation des actifs très risqués (centrales électriques) dans des conditions de marché compétitif et semi-compétitif.

Par exemple, Bar-Lev et Katz (1976) et Humphreys & McClain (1998) ont utilisé l'approche de la théorie du portefeuille afin de proposer un parc de production optimal aux États-Unis, aux échelles régionales et nationales. Awerbuch & Berger (2003) l'ont utilisé pour l'optimisation du mix Européen de la production d'électricité. Notre travail est similaire dans le sens que nous analysons nous aussi un mix électrique national basé sur les coûts de production pour chaque unité d'électricité générée. Cependant, notre objectif est moins focalisé sur la volatilité du prix du combustible (quasi-inexistante en Iran) que sur les prix internationaux des combustibles fossiles observés sur les marchés internationaux. Nous prenons en compte ces prix internationaux en fonction de leur coût d'opportunité et non pas des prix résultant des subventions intérieures. Notre méthodologie est basée sur l'approche de Markowitz alors qu'on applique un processus aléatoire de Monte-Carlo pour évaluer le coût total de la production, non seulement pour chaque technologie de manière indépendante mais aussi pour l'ensemble du portefeuille. En fin de compte, plusieurs solutions optimales (portefeuilles optimaux) sont proposées basées sur des aversions au risque des investisseurs, qu'ils soient publics ou privés. Ce faisant, les investisseurs peuvent évaluer à la fois les unités de production conventionnelles (fossiles et nucléaires) et les sources d'énergie renouvelables en se référant à leurs coûts de portefeuille et leur risque associé. Dans ce chapitre, nous fournissons également un bref aperçu historique de l'industrie électrique de l'Iran et en particulier du secteur nucléaire. Cela sera utile pour mieux comprendre la situation politico-économique actuelle de la filière électronucléaire Iranienne.

Finalement, dans le dernier chapitre, une étude comparative a été réalisée sur la base des résultats obtenus dans les chapitres précédents. Ce travail a été fait pour mieux illustrer la similitude et surtout les différences de chaque parc de production national et des politiques énergétiques associées. Les analyses sont essentiellement axées sur les subventions mises en œuvre dans ces pays et leurs impacts sur la tarification et les prix finaux des matières premières énergétiques, y compris l'électricité. De nombreuses suggestions de réforme ont été proposées basées sur les solutions et stratégies socio-économiques les plus optimales. Dernier

point mais non des moindres, les conséquences bénéfiques de la réduction des subventions (et éventuellement leur retrait total) sur les unités de production non-fossiles ont été examinées.

J'espère que ce travail pourra être considéré comme une petite contribution à l'Économie de l'énergie et à l'analyse des politiques publiques énergétiques dans cette région, qu'il puisse s'avérer utile pour les experts et les chercheurs travaillant dans ce domaine, et pourquoi pas ouvrir la voie à de nouvelles recherches.



## General Introduction

Since the emergence of the electric power generation industry in many oil and gas producing countries, fossil fuels became the main source of power generation due to their abundance and availability.

In almost all of the oil and gas producing countries, electricity industry flourished under a monopolistic system mainly managed by the public authorities and the states. The emergence of Saudi Electricity company (SEC), Egyptian Electricity Holding Company (EEHC) and Iran power Generation and Transmission Company (TAVANIR) respectively in Saudi Arabia, Egypt and Iran, which own and manage almost all of the national power generation, transmission & distribution, are the very revealing examples of public authorities involvement in this sector.

Even after the decision of these countries to go towards more competitively and privatization of power industry, still fossil fuels remained the main sources of electricity. This is too simply because of the very low domestic oil and gas prices and huge subsidies provided by the government even to the private power producers. This trend has been gradually halted as the governments decided to go through more rationalization of their natural resources. High oil prices (and natural gas of course indexed on the crude oil) observed in the international markets, specially following two consecutive oil shocks, contributed a lot to this philosophy of natural resources rationalization. Higher energy commodities prices in the international market means more very profitable export opportunities and consequently less and less incentive to somehow waste these valuable resources in inefficient processes of power generation at home. Not only the international markets prices brought incentives and motivations, but also the technological progress was also a very effective driver. As the learning curves (representing the decreasing cost of production over time) of various non-fossil fuel based technologies started to improve and therefore their costs reduced, fossil fuel power plants were considered more and more as inefficient and costly ones.

For sure, economic and financial analysis and perspectives are the most important drivers behind de-carbonization of oil and gas producing countries generation mix, but they are not the only ones. Environmental concerns and political decisions also plaid very important roles. Both global environmental factors (greenhouse gas emissions and global warming) and

locational ones (harmful suspended particles, NO<sub>x</sub> and SO<sub>x</sub>) have become important issues among political and governmental groups and entities.

Moreover, there is also the very important factor of political economy and philosophy which is tightly geared to ideological issues, particularity in many oil and gas producing countries located in the MENA (Middle East and North Africa) region. The idea that national resources, including oil and gas, are given by the divine power and should be used by the concerned population for free. Or perhaps it is better to say almost for free, as producer can charge only its minimum production costs. This way of thinking was the main idea behind the creation and promotion of subsidies since the discovery and production of fossil fuels in MENA countries.

However, since 1980s more discussions have been opened among policy makers of these countries over the better utilization and consequently better distribution of these naturally given wealth between people. And it was under this political philosophy that trend towards de-carbonization of national electricity mix was suddenly accelerated. Anyways, further discussions and analysis over these ideological matters are out of the scope of this study and we leave it for sociologists, political scientists and other experts in economic philosophy. In this work we mainly focus on the economic analysis of electricity mix de-carbonization and in our approach we attempt to be as much as possible positive rather than normative. However, in each chapter, after observing the results coming out of the economic modelling effort we propose some economic policy suggestions which could bring more economic benefits for national portfolios.

In this purpose we have chosen three different countries from MENA region: Saudi Arabia, Egypt and Iran. On one hand, all of them are oil and gas producing countries and very similar to each other from power sector structure point of view. They use a lot of oil and natural gas for power generation and these fossil resources are highly subsidized. All of them have started the transition process to market based competitive system to some extents. But still central planning way of economic decision making is very present. On the other hand, there exist many differences between them in terms of: energy policies, geopolitical and geographical situations, power generation mix structure, both natural and human resources and finally economic structure and institutions.

Taylor-maid economic modelling methodologies were used for each country. Models constructed according to the specific electricity sector structure of each case. In the first chapter we modelled the national power generation mix of Saudi Arabia. Total generation cost minimization approach was considered under linear programming (LP) frame work. In the literature we can find many examples such as Xydis & Koroneos (2012) and Chang & Li (2013) who applied LP methods for analysing and optimizing the future generation mix of some Asian countries. What is novel in our approach is the usage of multiple steps linear programming method. In this case, we constructed three optimization models respectively for short, medium and long-term national power generation mix of the country. In simple words we take a snapshot of the current and the future Saudi Arabia generation mix. Future generation mix structures are constructed based on the Saudi electricity related authorities' announcements in terms of investment options in the power sector of the country. In view of the central planning nature of electric power industry in Saudi Arabia, this methodology seems to be one of the most adapted and reliable way of tackling the following question: Should Saudi Arabia take into account seriously and continue the promotion of its non-fossil fuel based power generation strategy or not? And if yes, what would be the tangible economic benefits of this action?

Firstly, the details of the national power generation structure are analysed. Then, we study the potential of various electricity sources for Saudi Arabia. This has been done from both economic and technological point of views. Finally, the model is presented with the development of results for various scenarios. Information regarding the electricity pricing applied in Saudi Arabia is also provided so as to bring new elements of reflection aiming to reach optimality in the power generation system.

In chapter II, we examine the case of Egyptian power generation mix. Contrary to the case of Saudi Arabia, this time we used a dynamic approach for our modelling purpose. We use dynamic linear programming model so as to be able to reveal a smoother investment process during the studied time frame. The main reason behind this dynamic way of looking at investment, is the fact that current investment environment in this country is very uncertain. Following the Arab Spring and removal of Mr. Mubarak from power, electricity sector faced with a huge uncertainty in terms of prices, planning, management and of course investment. Under these circumstances we preferred to use a dynamic model with small time steps rather than a static model with large time lags. Sophisticated sensitivity analysis for various

parameters of the model (such as discount rates for example) has been performed so as to better show the uncertain nature of Egyptian power sector and its impact on investment decisions.

Moreover, the Egyptian authorities explicitly announced their concerns regarding environmental issues and pollution reduction. Therefore, sensitivity analysis over CO<sub>2</sub> prices is also performed to reveal the impact of price variation over the investment trends. Results illustrate clearly the interest of investment in non-fossil technologies for high CO<sub>2</sub> prices, particularly under low and medium discount rates. All the modelling process for the Egyptian power generation mix is performed under the assumption of 20% renewable integration in the national mix, already announced by the governmental authorities. Back-up units' costs were also implemented in the model accordingly; stand on the technical properties of the Egyptian generation mix.

Finally, in chapter III, we treated the case of the Iranian power generation sector. As there is a very high tendency toward privatization and market competition in Iran (recently the government has even established an Exchange dedicated entirely to power sector) we have adopted a totally different approach in our modelling process. Markowitz mean variance portfolio approach was considered for the Iranian electricity mix analysis. In the literature (thoroughly elaborated in the associated chapter) these models are considered to be very powerful in evaluation of highly risky assets (power plants) under competitive and semi-competitive market conditions.

For example, Bar-lev and Katz (1976) and Humphreys & McClain (1998) used portfolio theory approach to propose an optimal generation mix in the US, from both regional and national perspectives. Awerbuch & Berger (2003) used it for European technology mix optimization for electricity generation. Our work is similar in a sense that we also analyse a national generation mix based on generation costs for each power unit. However, our focus is less on the fuel price volatility (quasi inexistent in Iran) and more on the real international prices of fossil fuels in the markets (according to their opportunity costs) and not domestic subsidies. Our methodology is based on Markowitz' approach while we apply Monte-Carlo random process for evaluating the total cost of generation, not only for each technology but also for the whole portfolio. In the end, several optimal solutions (portfolios) are proposed based on the risk averseness of the investors, whether public or private ones. By doing so, investors can evaluate both conventional (fossil and nuclear) and renewable energy sources in

refer to their portfolio costs and relative to their associated risks. In this chapter, we provide also a brief historical overview of power and particularly nuclear industry in Iran. This could be helpful to understand better the current politico-economic situation of the Iranian electro-nuclear sector.

Eventually in the last chapter, a comparative study has been realized based on the previous chapters' outcome. This work was done for better illustrating the similarity and especially differences of each national technology mix and related energy policies. Analyses are mainly focused on the subsidies implemented in these countries and their impacts on the optimal pricing of energy commodities, including electricity. Suggestions for reforms are proposed based on the most optimal socio-economic solutions and strategies. Last but not the least, beneficial consequences of subsidies reduction (and eventually their total removal) over non-fossil-fuel power units are examined.

We hope this job could be considered as a small contributor to energy economics and policy fields and to be useful for experts and researchers working in this area and can open doors for further research.

# **Chapter 1: Transition to Non-Fossil Fuel Based Power Units in Saudi Arabia**

## Résumé

En Arabie saoudite, les combustibles fossiles sont les principales sources de production d'électricité. En raison de l'importante croissance économique et démographique, la consommation d'électricité en Arabie Saoudite a augmenté et devrait continuer à augmenter à un rythme très soutenu. À l'heure actuelle, plus d'un demi-million de barils de pétrole par jour est utilisé directement pour la production d'électricité. Dans ce chapitre, nous évaluons la production d'électricité du pays et ses conditions futures à travers une approche de modélisation. À cette fin, nous présentons la situation actuelle en détaillant le mix de production électrique existant. Ensuite, nous développons un modèle d'optimisation du secteur de l'énergie qui vise à définir le meilleur modèle de production et d'investissement pour atteindre la demande anticipée. Par la suite, nous procédons à une analyse de sensibilité afin d'évaluer la robustesse du modèle pour la prise en compte de la variabilité de l'intégration des ressources alternatives (non-fossiles). Les résultats soulignent que les choix d'investissement dans le secteur électrique affectent fortement les exportations pétrolières potentielles de l'Arabie Saoudite. Par exemple, par la décarbonisation de la moitié de son mix de production, l'Arabie Saoudite peut libérer environ 0,5 Mb / j barils d'équivalent pétrole à partir de 2020. En outre, la réduction du coût total de production d'électricité peut atteindre jusqu'à environ 28% par an à partir de 2030 si l'Arabie Saoudite parvient à atteindre la structure de génération la plus optimale introduite dans le modèle (50% de la production des énergies renouvelables et des centrales nucléaires et 50% des centrales fossiles).

Mots-clés: Modèle de la production d'électricité; Arabie Saoudite; Parc de la génération d'électricité

## **Abstract**

In Saudi Arabia, fossil-fuel is the main source of power generation. Due to the huge economic and demographic growth, the electricity consumption in Saudi Arabia has increased and should continue to increase at a very fast rate. At the moment, more than half a million barrels of oil per day is used directly for power generation. Herein, we assess the power generation situation of the country and its future conditions through a modelling approach. For this purpose, we present the current situation by detailing the existing generation mix of electricity. Then we develop an optimization model of the power sector which aims to define the best production and investment pattern to reach the expected demand. Subsequently, we will carry out a sensitivity analysis so as to evaluate the robustness of the model by taking into account the integration variability of the other alternative (non-fossil) resources. The results point out that the choices of investment in the power sector strongly affect the potential oil exports of Saudi Arabia. For instance, by decarbonizing half of its generation mix, Saudi Arabia can release around 0.5 Mb/d barrels of oil equivalent per day from 2020. Moreover, total power generation cost reduction can reach up to around 28% per year from 2030 if Saudi Arabia manages to attain the most optimal generation mix structure introduced in the model (50% of power from renewables and nuclear power plants and 50% from the fossil power plants).

Keywords: Electricity Generation Model; Saudi Arabia; Power Generation Mix



## Introduction

Although Saudi Arabia is one of the largest oil producers in the world, rising dependence on hydrocarbons in meeting domestic energy demand will prove very challenging for the country. Hydrocarbons (both oil and gas) are the main fuels for Saudi Arabia's primary energy supply but gas supply has been very tight recently as the country cannot raise the production rapid enough to meet the fast growing demand. Natural gas is an important input for petrochemicals industry but is also a key fuel for the electricity sector. Growth of natural gas into electricity sector has suffered in recent years as the main focus has been on developing petrochemicals. Hence, oil-fired electricity has had to increase to satisfy strong electricity demand. This is a significant problem for the government as the whole economy relies heavily on oil export revenues and if the national oil demand continues to rise (mainly driven by electricity demand) the government will face with decreasing oil export income. The oil sector accounts for almost 45% of budget revenues, 55% of GDP and oil revenues constitute 85% of Saudi Arabia's total export revenues (IMF 2014<sup>1</sup>).

Such as in many oil producing countries, Saudi Arabia's government provides subsidies to energy products. This is seen as a direct way of redistributing the hydrocarbons rent to the population. These subsidies represent undoubtedly a heavy burden for the economy. They account for 9% of the total GDP and for the power sector alone, they cost almost 15 billion dollars every year (IEA 2013<sup>2</sup>).

Currently Saudi Arabia with around one-fifth of the world's proven oil reserves is the biggest oil producer in the Organization of Petroleum Exporting Countries (OPEC). With important investments in the oil sector and low production costs, Saudi Arabia is likely to remain the world's largest net oil exporter. Thus, the Saudi oil production is 544 million of tons (Mt) in 2011 and the net exports reach 355 Mt for the same year (IEA, 2012).

Saudi Arabia is likely to be the supplier of swing (spare) capacity to the global market for years to come. This market stabilizing role became evident in 2011 when Libyan exports were lost and Saudi Arabia ramped up production by 1.5 Mb/d in July 2011 from 9.8 Mb/d earlier in the year.

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<sup>1</sup> International Monetary Fund, country report, N° 121292, Saudi Arabia, September 2014

<sup>2</sup> International Energy Agency Subsidies Database 2013

Over the next two decades, Saudi’s power generation capacity is predicted to reach 120 gigawatt-electric (GWe) (SEC 2010). The combination of Saudi Arabia’s rapidly expanding population and industrial infrastructure, along with low electricity tariffs, has increased the demand on electricity utilities (averaging 8% annual growth over the period). This dramatic load increase has led to shortages, brown outs, black outs and power rations in various parts of the country. Electricity demand which now stands at around 50GWe (around 200 terawatt hours (TWh)) of yearly production, is predicted by the government to increase from 80GWe by 2020 to more than 120GWe by 2030.<sup>3</sup> This increase of power production capacity is illustrated in figure 1-1.

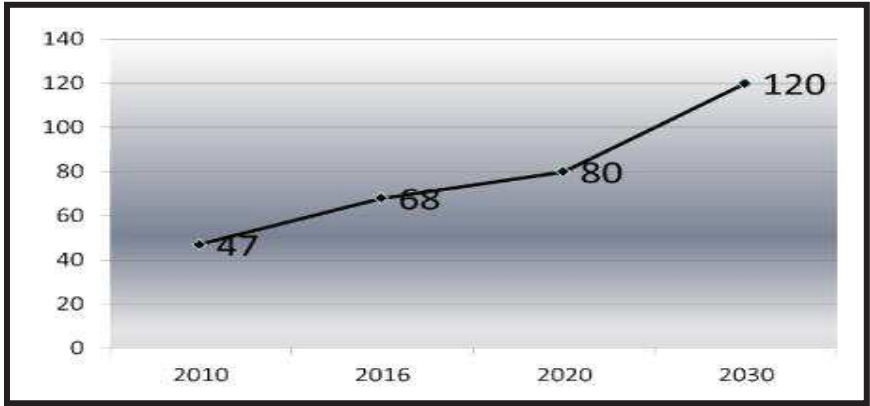


Figure 1-1: Power generation growth forecast in GW for Saudi Arabia

(Source: SEC/KACARE 2010)

For the time being in Saudi Arabia, 100% of power generation is based on the fossil fuel sources (oil and gas). Figure 1-2 and figure 1-3 show respectively the share of different power units and fuels in the power generation mix of the country.

<sup>3</sup> Electricity and cogeneration regulatory authority 2010.

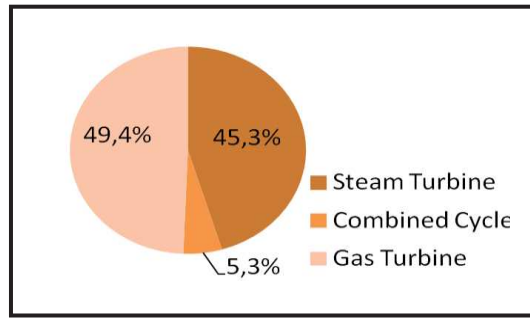


Figure 1-2: Existing generation capacity profile in Saudi Arabia

(Source: SEC 2010)

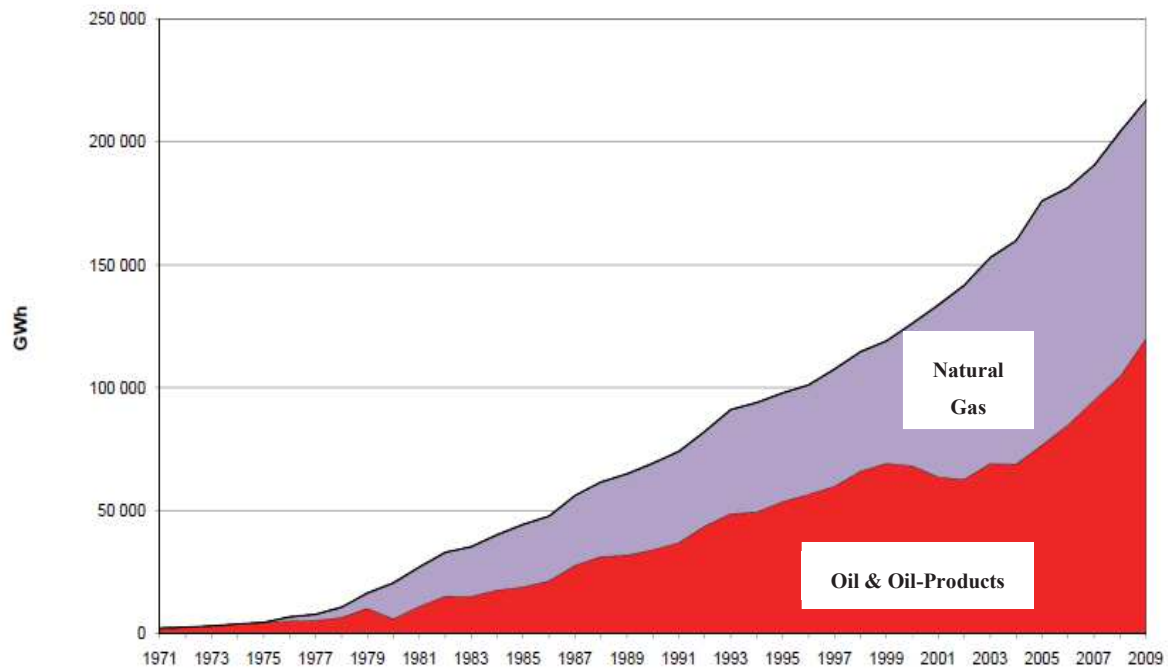


Figure 1-3: Electricity generation by fuel in Saudi Arabia

(Source: OECD/IEA 2011)

Moreover, almost 30% of the power generation in Saudi Arabia is provided by burning directly the crude oil in the power generation plants across the country. Table 1-1 shows the shares of the oil and oil-products in the electricity generation of Saudi Arabia in details.

Crude Oil	30%
Diesel	15%
Heavy Fuel Oil	10%

Table 1-1

Source: ECRA 2014

Increasing oil and gas domestic consumption and the resulting impact on export revenues is not a very good option for the Saudi government due to both economic and political reasons. In this chapter, we evaluate the present and future potential of using non-fossil fuel based energy in the power sector of this country.

A linear programming optimization framework was used to assess the costs and savings of expanding the role of non-fossil fuel based power sources in electricity supply. LP (Linear programming) cost minimizing is an approach that systematically evaluates potential power supply to satisfy the demand at the best societal cost. We analyse what the incremental cost would be if each sources of power generation were to integrate the electricity supply of the country. In pursuit of this objective, we provide a review of relevant non-fossil and fossil based power unit choices on the basis of resource potential, cost and economic benefits. Several choices of technologies that are or are expected to be technically and economically feasible over the next two decades have been identified and incorporated into the modelling effort.

The main reason behind choosing a discrete linear programming model for Saudi Arabia's power generation mix goes along with the nature of the observed decision-making process for energy systems in this country. Long-term investment planning for energy systems (whether for oil or natural gas or power generation) in Saudi Arabia has always been realized under central planning approach. In which the authorities, designated by the government for each branch of the national energy system, generate the investment plans of the related sectors every 5 to 10 years. And power generation sector has never been apart from this investment planning system. That's why we have adopted a discrete LP modelling approach with large steps (10 years) so as to bring our modelling process further near to the reality as much as possible. In other words, our model generates the total costs at each step and every next step's calculations/simulations are based on the previous step's results. In even more simple words, the model simulates the actions of the central planner who observes the current status of the electricity generation mix in order to make decisions for the next 10-year investment period.

In the next section we develop in details the structure and the specific properties of the above-mentioned linear programming model. The terms “static” is often used so as to better reveal the discrete-large-step nature of our model.

## **Methodology and Literature Review**

Electricity generation should be provided by a large set of power plants which are characterized by different technologies associated to a very large spectrum of fixed and running (variable) costs. Consequently, this leads to an optimal usage and investments so as to satisfy the current and future demand. Optimizing the overall electricity cost of production from different types of plants enables us to rank the existing production units. Indeed, when the electricity demand increases and the available power (in the lowest cost category) is not enough, producer must switch to the generation unit whose cost category is just one step above the previous one. In other words, we rank the use of power plants according to their growing variable cost (so-called "merit-order" process).

The main contribution of this study is to analyse an optimal pattern of the Saudi power generation mix through an LP model (based on the above-mentioned structure) and to reveal the impact of renewable and nuclear integration into the electric system under different penetration-range scenarios. Afterwards, the financial and economic gains (or perhaps losses) will be quantified by looking at the amount of fossil-fuel probably released and injected to the market instead of internal/national usage in the power sector.

First, let's have a brief look at the concept and application of LP models (for more information please refer to Appendix 1-C). LP method was expanded as a planning tool that has found its greatest use in goods and services production optimization in large firms. Its significant benefits come from centrally coordinating organization-wide production process. Leonid Kantorovich (1958) and George Dantzig (1951) independently invented linear programming. The latter for optimizing manpower planning in the US military and the former to optimize the plans of the central planning agency in the Soviet Union. One of the first commercial applications of LP was the Manne (1958) model of an oil refinery. Soon after, power industry also began using it for the investment planning (Massé & Gibrat 1957). Installed capacity expansion models became a standard application of LP in utilities. It also became an important tool for understanding markets when Paul Samuelson (1952) and

Stephen Enke (1951) recognized that the “Simplex Algorithm” developed by Dantzig (1951) to solve LP programs, was a very useful method for finding equilibrium in a competitive market. Of course markets without market power exercise and where prices equal the cost of the marginal unit of production.

The most common view over the use of LP program is to think of the model in standard algebra as a set of equations that explain how the solution has to meet conditions that represent the coordination of activities in an organization. Another way to frame the LP model is in terms of planner activities where each activity (variables in the model) is considered as input/output Leontief production function with fixed conversion (input to output) ratios. Planner can decide for each activity’s production level, depending on whether or not it is profitable to produce. Supply functions are multiple-step functions with increasing costs on the steps and a constant marginal cost for each step plus a maximal capacity (Figure 1-4).

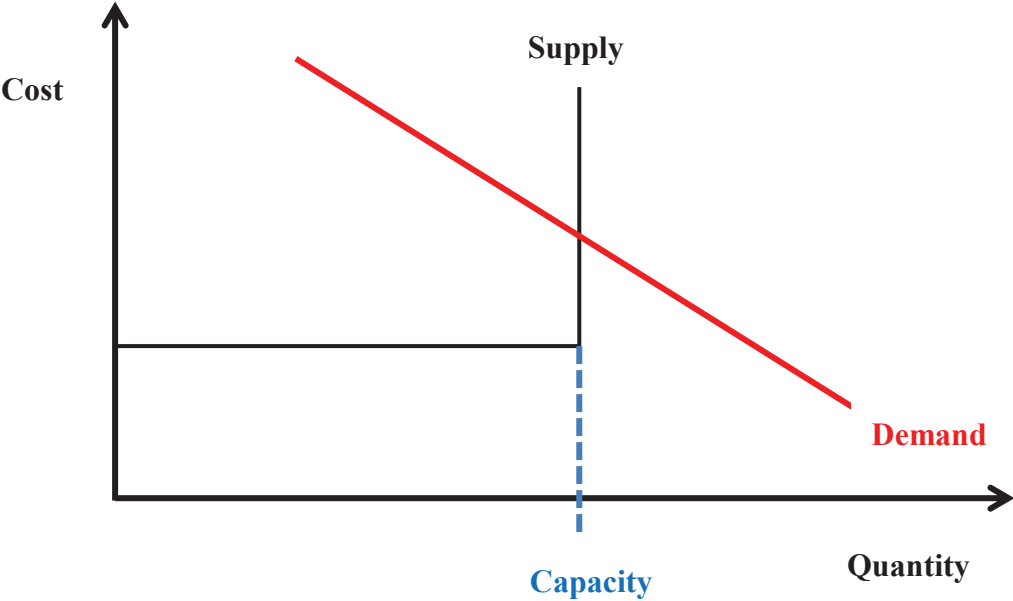


Figure 1-4

Demand function could be represented as fixed quantities that do not vary with price. For each supply-step, three situations can occur. When the demand is higher than the supply-step capacity, hence all the capacity is used and price (result of the market equilibrium) will go beyond the operating costs and there is an economic margin (also called “scarcity rent”). In case that the demand curve cut the supply-step curve, the market equilibrium equals exactly

the operating cost of the supply-step and finally a demand lower than the supply-step results in zero production of the concerned activity (figure 1-5).

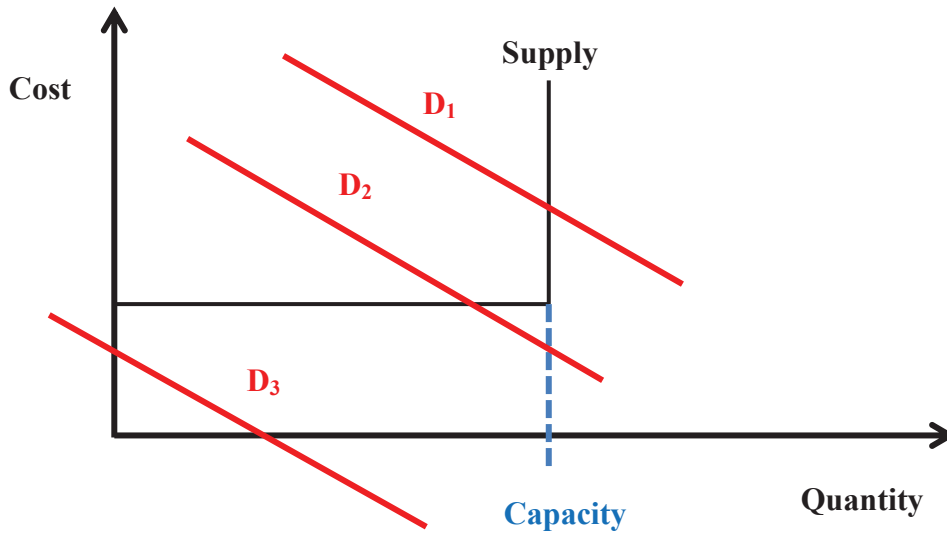


Figure 1-5

Variations in the proportions of inputs and outputs are captured by having multiple activities (i.e. various power units in our case) with different proportions that can vary the mix of inputs and outputs in the solution (figure 1-6).

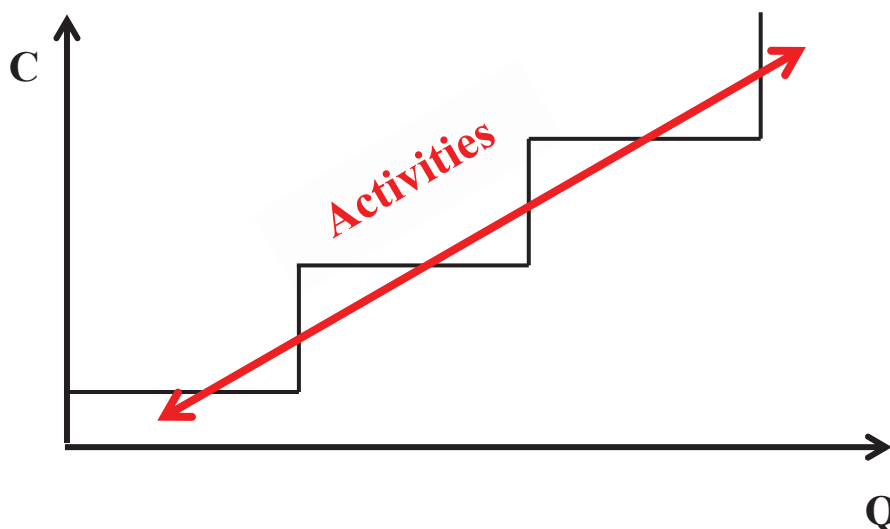


Figure 1-6

Constraints express limits on resources, demand requirements, input and activities characteristics, policy and technical restrictions. The levels of the activities in the optimal

solution depend on the choice of objective function. Most commonly used objective functions are profit/economic surplus maximization and production cost minimization. The latter is used in our modelling effort.

During the past decades, a huge body of literature related to the application of sophisticated energy optimization and simulation scenarios have been carried out for optimal planning of the future national energy systems (Abubakat et al. 2013, Haidar et al. 2011, Hainoun et al. 2010, Ostergaard 2009, Sorensen et al. 2008 and Nielsen et al. 2007). Grouping existing literature, there are several studies seem to be related to the optimization of the use of renewables and the assessment of existing tools and optimal penetration rates of renewables in the power systems (Segurado et al. 2011, Kaldellis et al. 2009, Lund et al. 2009 and Karlsson et al. 2008). An overview of various existing models and advances in the renewable energy integration into the power systems have been provided in Olabi 2013 and Olabi 2012. For instance, the EnergyPLAN model has been used for the simulation and optimization of renewable usage in the Danish (Lund & Mathiesen 2008) and Irish (Lund et al. 2010) power systems. Both of them are based on a deterministic input/output bottom-up simulation model (Lund et al. 2006). A study for Algeria, Morocco and Tunisia has been done by Brand & Zingerle so as to analyse the impact of renewables integration into their electricity systems. Mazhari et al. used system dynamics and agent based modelling approach in order to find the most optimal and economical mixture of storage capacities and solar plants. Lund et al. have stressed the role of district heating in renewable energy systems while Karlsson and Brouwer did point out the role of fuel cells and hydrogen in the future energy systems.

Various types of linear programming models have also been used for future optimal generation mix simulations. Xydis & Koroneos (2012), stated the role of solid wastes in future energy systems, while Chang & Li, pointed out the role of all the renewable energies options for the future generation mix of ASEAN<sup>4</sup> countries.

Although numerous studies have been conducted on the optimization and simulation of future energy systems with various rates of pure renewables penetration, limited papers have appeared on the optimization of power systems with both nuclear and renewables penetrations which is the main focus of this study.

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<sup>4</sup> Association of Southeast Asian Nations



Total electricity generation cost minimization, is one of the main modelling approaches in power generation optimization and simulation. Examples of such models include POLES<sup>5</sup> (Criqui 2001), MARKAL<sup>6</sup> and TIMES<sup>7</sup> (Loulou et al. 2004). The main idea of these models is to explain electricity prices from the marginal generation cost. In this case, assumption over the future electricity prices does not have to be made. Focusing on minimum generation cost implies minimizing the cost to be transferred to the final consumers, irrespective of the electricity price. The key advantage of this method is to analyse the producer behaviour facing with a mix of deferent types of constraints such as economic, technical and environmental ones. Our approach is similar, in the way that we develop a model where the total costs are to be minimized under certain constraints and scenarios developed in the next sections.

### **Power Generation Means in Saudi Arabia**

The Saudi Electricity Company (SEC) owns almost 85% of the countries installed capacity. It is owned by the government and Saudi Aramco (85%), with the remainder being publicly traded and owned by the Saline Water Conversion Corporation (SWCC). The remaining production capacity is associated with some energy intensive entities, like desalination (operated and owned by SWCC) and plants owned by large consuming companies, such as Saudi Aramco and Saudi Arabia Basic Industries Corporation. Saudi's transmission grid is split into four operating areas: Central (COA), South (SOA), East (EOA) and West (WOA). Interconnections between the operating regions are sparse as historically it was cheaper to transport oil than electricity. There is an international transmission system between Saudi Arabia, Kuwait, Bahrain, Qatar, UAE and Oman completed in 2011. Given Saudi Arabia's power market is very tight, as of Kuwait's; it is not easy to envisage any future potential electricity trade flows. Even if these Persian Gulf countries are interconnected, it is operating more as a balancing mechanism.

Before the power generation model construction, we analyse the potential of different non-fossil fuel based technologies such as geothermal, wind, solar and nuclear in Saudi Arabia. Feasibility studies have been realized in order to identify the most suitable and reliable technologies for this region based on the technical, economic and geographical characteristics.

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<sup>5</sup> Prospective Outlook on Long term Energy Systems

<sup>6</sup> MARKet ALlocation

<sup>7</sup> The Integrated MARKAL-EFOM System

Due to the climate and regional properties of this country, some power units are not supposed to be useful and adapted to the national generation mix. In the following, we analyse each technology in detail and try to find out those who can be considered for the Saudi power generation mix from climatic, economic and technological point of view. Finally, the existing thermal power units in Saudi Arabia have been described.

## **Geothermal Energy**

While not really abundant, geothermal energy potential does exist in Saudi Arabia (Alnatheer 2006). This technology is not entirely a renewable resource since the geothermal wells can be depleted over time. These resources belong to two types of technology, either hydrothermal or hot dry rock. Binary and flash technologies are the main approaches generally used to extract heat from geothermal wells. Although initial investment costs of the plant are relatively high, geothermal energy could become economically competitive (on a life cycle basis) to other sources of power generation (Boyle 2004).

Some studies have suggested the potential of combined solar and geothermal power so as to provide water and electricity in Saudi Arabia (Oktun & Sayigh 1976). Saudi Arabia is somehow rich in terms of various geological features, with around 10 hot springs located in the regions of Gizan and Al Lith in the southern part of the country (Taleb 2009). Some of these thermal springs could be utilized for electricity generation, even though none have yet been exploited (Lund et al. 2005). Alnatheer (2006) argued that the exploitation of geothermal energy in Saudi Arabia is not cost-effective, even when compared with other renewable sources such as solar and wind power. Moreover, a set of renewable power sources scenarios were developed for Saudi Arabia in a study provided by Al-Saleh et al. (2008) in which the prospects of geothermal energy (both power and heat) were not considered as being sufficiently viable. Taleb (2009) identified both technical and non-technical barriers of geothermal energy utilization in Saudi Arabia. The most important reasons which are claimed are the uncertainty regarding available resources (the lack of technical feasibility studies), the lack of financial incentives and high capital cost of this technology (compared to the power generation based on oil), and the poor public acceptance of renewable energy sources in general and particularly geothermal one and lack of neither academic nor professional training in this field.

At last, due to the above mentioned arguments and existing barriers for the development of this technology in Saudi Arabia, we don't consider the integration of geothermal energy as an option for the future energy mix of the country (neither in the optimization model nor in its associated scenarios).

## **Wind Energy**

There are many locations in Saudi Arabia that the annual speed of wind (averaged) goes beyond 4 m/s at a height of around 20m. Al-Abbadi (2004) showed that the wind annual average speed can reach even 5.7m/s and 5.4m/s in Dhulum and Arar sites respectively for speeds higher than 5m/s for around 50% of the time. In spite of this rather high potential wind power in Saudi Arabia (compare to the other Southern Persian Gulf countries) there is not an upright future for this energy in this country, at least in the short and medium terms. In fact, the highest and most optimistic wind energy potential in Saudi Arabia was estimated to yield around 20 TWh per year (Alnaser 2009). This is a considerable amount seeing the climatic conditions of the region but compare to the other renewable options such as solar (both concentrated and photovoltaic); it does not represent even 1% of their estimated potential.

Therefore in this study we won't consider wind energy as a high potential option for the future power generation mix of the country due to its negligible potential and huge costs (currently) compare to conventional plants. Moreover, there has not been any official declaration from the government or any energy authority regarding a vast investment in this area up to now. And the existing projects are all at a very small scale (decentralized) or are just under R & D and pilot stages.

## **Solar Energy**

Solar energy has been accepted as a key source of energy for the future in Saudi Arabia. Saudi Arabia has enormous potential for exploiting solar energy. Its geographical location, widespread unused desert land and clear skies, make it an excellent candidate for this technology. The average solar radiation falling on the Arabian Peninsula is around 2200KWh/m<sup>2</sup> per year (Hepbasli & Alsuhaibani 2011).

According to the Saudi Solar Radiation Atlas which is a governmental document concerning the solar radiation of the country, Saudi Arabia has vast areas subject to strong GHI<sup>8</sup> and fractions of DNI<sup>9</sup> which are respectively ideal for Photovoltaic (PV) and Concentrating Solar Power (CSP) technologies.

Just for giving an example, within about 2000 KWh/m<sup>2</sup>/y of DNI, it has been estimated that the potential annual energy yield of CSP technology in Saudi Arabia is around 124,560 TWh.<sup>10</sup> This amount represents around 650 times the total electricity consumption of the country in 2009. This reflects the fact that CSP technology must be considered between the most suitable renewable technologies in the Saudi's future energy mix. Hence, in this study and in our model's scenarios we do consider solar option in the future electricity generation mix of the country. Load factors' intervals considered for both PV and CSP technologies in the model are respectively equal to 0.2-0.25 and 0.34-0.5 (K.A. CARE 2010). Due to the fact that solar technologies (PV and CSP) are the only renewable sources envisaged in this study, hereafter we use the term "renewable energies" for these technologies.

## **Nuclear Power**

Nuclear power generation provides around 7% of the world primary energy supply and about 14.7% of the electric power generation.<sup>11</sup> Increasing improvements in safety means, using experience, plant availability and of course economy, made nuclear energy competitive with other means of electricity generation. For the time being 436 nuclear reactors generate around 370 GW of electric power all around the world (IEA 2011). While there are many reactors in operation in the US, Europe, Japan and China, the other regions of the world do not use this technology within a significant amount. In Africa, it is only South African Republic which has two operating reactors providing only 1.8GWe of electricity. In the Middle-East only one nuclear power plant with the capacity of 1GWe is operating in Iran. Despite of the large diversity in term of design, only two types of reactor dominate nuclear power generation. 85% of operating reactors are the light water type reactors including the Russian RBMK reactor. Majority of these reactors are Pressurized Water type reactors and the rest of it are Boiling

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<sup>8</sup> Global Horizontal Irradiance which is equal to the total solar radiation.

<sup>9</sup> Direct Normal Irradiance which is equal to direct beam radiation.

<sup>10</sup> German Aerospace Center (DLR) report, 2010. *Concentrating Solar Power*.

<sup>11</sup> Nuclear Energy Outlook 2008.

Water ones. Both technologies use slightly enriched Uranium (3-5%) as fuel which does not create any potential proliferation risk. Nuclear fuel, in contrary to oil and gas resources, has extended life time and is not considered as a depleting resource.

Therefore, this technology is not a negligible source of electric power choice for Saudi Arabia as an energy source (the model will tell us more about its economic viability) and we consider it in our model's scenarios. Moreover, Saudi government has recently announced its intention to use this technology for the future power generation. According to the government officials, Saudi Arabia plans to build about 16 nuclear power reactors, with the capacity of around 20GWe, over the next 20 years by spending around \$7 billion on each plant. This \$112 billion investment plan (totally 16 reactors) is supposed to provide one-fifth of the Saudi Arabia electricity generation for residential and industrial usage and in some cases for desalination of sea water which is very critical for this country. Most likely, the reactor locations will be along the Persian Gulf or Red Sea. The exact locations are still under discussion within Saudian authorities because of not only technically related issues such as: earthquake tests, nearness to the water source (for both cooling and desalination) and connection to the future regional markets and grids, but also many geopolitical concerns as the relationship of Saudi Arabia is not very stable with all of the neighbouring countries and nuclear power plants are considered as very strategic infrastructures.



Figure 1-7A: Potential locations of future nuclear power plants in Saudi Arabia

In addition to power generation, another factor behind this motivation for nuclear plants is “desalinated water” production to meet increasing demand for drinking water. Saudi Arabia is currently the world’s largest producer of desalinated water with 30 desalination plants across the country. It represents already almost 18% of the world total production and the country envisages doubling its capacity over the next decade.

In spite of the government’s effort, the consumption level of water is reaching alarming levels. Desalination plants provide around 60% of total water consumed by households with the remaining coming from depleting groundwater aquifers. Desalination sector already accounts for more than half of country’s oil consumption. Nuclear plants will be the most suitable sources of energy for future desalination plants as they can afford significant amount of continuous centralised electric power near the sea water which is an ideal location for desalination units.



Figure 1-7B

### **Thermal Fossil-Fuel-Based Power Plants and their Situation**

Currently, electricity production in Saudi Arabia comes thoroughly from thermal equipment family, except coal and nuclear ones. Hence, the current electricity supply system in our optimization model is composed of only this type of power plants. Their operating principle is as following: combustion can heat a fluid which produces, in a turbine, mechanical energy converted into electrical one by a generator. There are currently three main types of thermal fossil-fuel-based power plant in Saudi Arabia:

First, the gas turbines whose exhaust gases produced directly goes for the energy required to drive the alternator. Efficiency of this mode of production is relatively low (15 to 30%) and operating costs, including fuel which accounts for most of them, are very important. However, gas turbine power plant has two major advantages over competing modes of production: first the investment cost is relatively low and secondly they have the distinction of being immediately available with a very low starting time. Gas turbine is an ideal element when used for a short period, when it is necessary to significantly and rapidly increase the production capacity to meet the demand. Hence, they are very adapted to be used during peak

loads. Hail-2 power plant located in Hail in Saudi Arabia is an example of this sort of thermal unit.

Second type is the combined cycle, which consists of installing counter-pressure (steam turbine) in addition to the gas turbine so as to maximize the electricity production. Indeed, it offers the opportunity to at least triple the production of electricity for the same heat, which can lead to overall efficiency of 50 to 60%. Ras Tanura power plant located in the Ash Sharqiyah belongs to this family of thermal units.

Finally the conventional thermal stations with two versions: the thermal oil and thermal coal. The operating principle consists of burning oil or coal to heat a fluid (most often it is the water steam) and then expansion of this fluid through a turbine that drives a generator. Despite a low overall efficiency (electricity produced is only 30-35% of energy input); it remains higher than that of Gas Turbines. In addition, operating costs are relatively low and allow to partially offsetting the heavy investment costs. However, these plants are very slow to start and ramp up, so they are not suited to respond quickly to a sudden increase in demand. Shuaibah power plant with the capacity of 3\*400 MW (gross) is an example of thermal oil units.

Figure 1-7C shows the locations of these power plants for all the four operating areas in Saudi Arabia: Eastern, Central, Western and Southern.



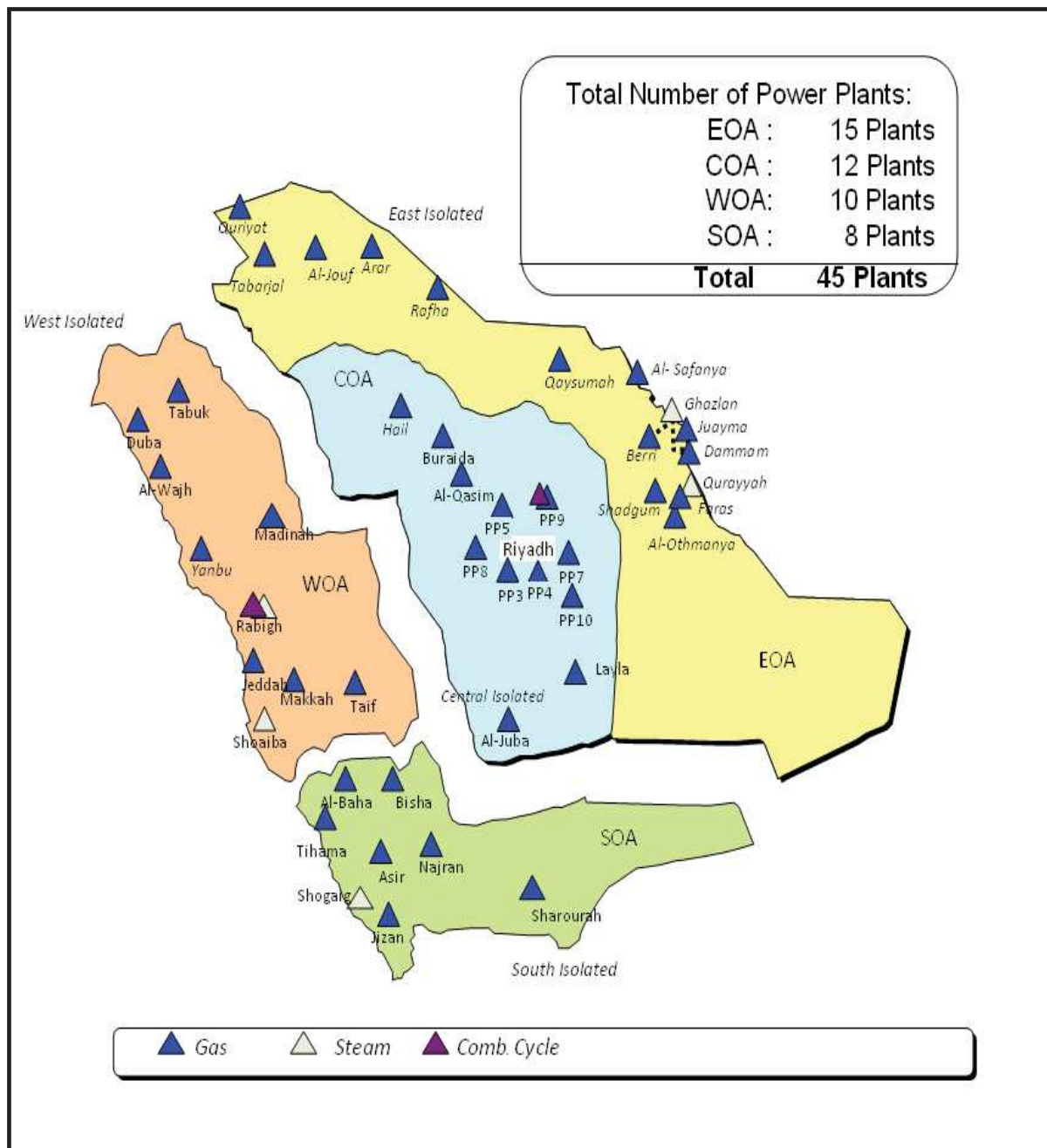


Figure 1-7C: Thermal power plants in Saudi Arabia

(Source: Saudi Electricity Company 2009)

## Modelling Framework

We model the current power generation mix structure of the country by using GAMS 24.0.2 (General Algebraic Modelling System) software within CPLEX as a solver. This cost minimization model contains 28 equations and 29 variables, the objective cost function that must be minimized and the demand constraints that have to be satisfied. For static short-term optimization (base year 2010), the production capacities must be respected and in the case of long-term optimization, investments are allowed.

The constraints of the model are the demand equations, the capacity constraints and the investment equations. In the demand equations for each season, the sum of the power generated by the power plants is greater than the demand. On the supply side, the power loaded from each unit is lower than the power capacities times the seasonal availability coefficients. Finally, the installed capacities are equal to the sum of the existing units and investments.

The objective function is a discounted cost function to be minimized. This cost function is the sum of the running costs associated to each generation unit for each seasonal time period and of the discounted capital costs of the units.

The model structure is as following (Schematic structure of the model is shown in Appendix 1-D):

$$\begin{aligned} \text{Min} \quad & \left[ \sum_i \sum_s H_s \times E_{it} \times p_{ist} + \sum_i I_{it} C_{it} \right] \\ & \frac{1}{\tau_{is}} P_{ist} \leq C_{it} \\ & \sum_i P_{ist} \geq D_{st} - AP_t \end{aligned}$$

In which we have the following variables and parameters:

$P_{ist}$  is the Power loaded on the grid by each equipment of type  $i$ , for the season  $s$  in year  $t$  (MW)

$C_{it}$ : The capacity of the equipment of type  $i$  in year  $t$  (MW)

$H_s$ : Length of the season  $s$  (hours)

$I_{it}$ : Investment cost of each unit of production (\$/kW)

$E_{it}$ : Variable cost of production for each equipment  $i$  (\$/kWh)

$D_{st}$ : Called power on the grid for the season  $s$  (MW)

$\tau_{is}$ : Coefficient of availability in each season for each equipment  $i$

$AP_t$ : Supply of the must-run or auto-producers (MW) if there is any

And the variables of the model are the powers loaded, coming from each type of unit ( $i$ ) for each season ( $s$ ) in year ( $t$ ).

### **Technical Properties and Costs**

Apart from fuel costs, which is described in details in next sections, the other variable and fixed costs of each type of power plant are also essential for the decision making process of the model. Plants' life-time and efficiency should also be incorporated in the model so as to be able to evaluate the potential amount of electricity (from technical point of view) that each power plant could produce. Table 1-2 provides the techno-economic properties of various thermal power plants used in the model. These values are derived from the studies done by IEA and NEA (2010) on power generation costs.

<b>Techno-economic data for each type of power plant</b>					
<b>Plant type</b>	<i>Nuclear Plant</i>	<i>CCGT Plant</i>	<i>Fuel Plant</i>	<i>Solar PV</i>	<i>CSP</i>
<b>Efficiency (%)</b>	33	57	38	*	*
<b>Investment cost (\$/Kwe)</b>	2050	534	364	3400	3000
<b>Life cycle (years)</b>	60	30	30	25	25
<b>Fix O&amp;M cost (\$/Kwe)</b>	46	8	8	50	60
<b>Variable O&amp;M cost (\$/MWh)</b>	0.8	1	0.3	0.5	0.5
<b>Average seasonal availability coefficients</b>	0.87	0.80	0.80	0.25	0.42

Table 1-2

(Source: IEA 2010 Median Case & SEC 2010)

### **Demand's Structure**

We know that the most important feature of electric power is its almost non-storability. This implies that production must be adjusted instantaneously to the consumption and ensures that equipment is functioning at full capacity at the time of peak demand, and even extreme spikes. Therefore, the load curve, which represents the continuing evolution of the power demand over time, is one of the fundamental elements of the power system optimization model.

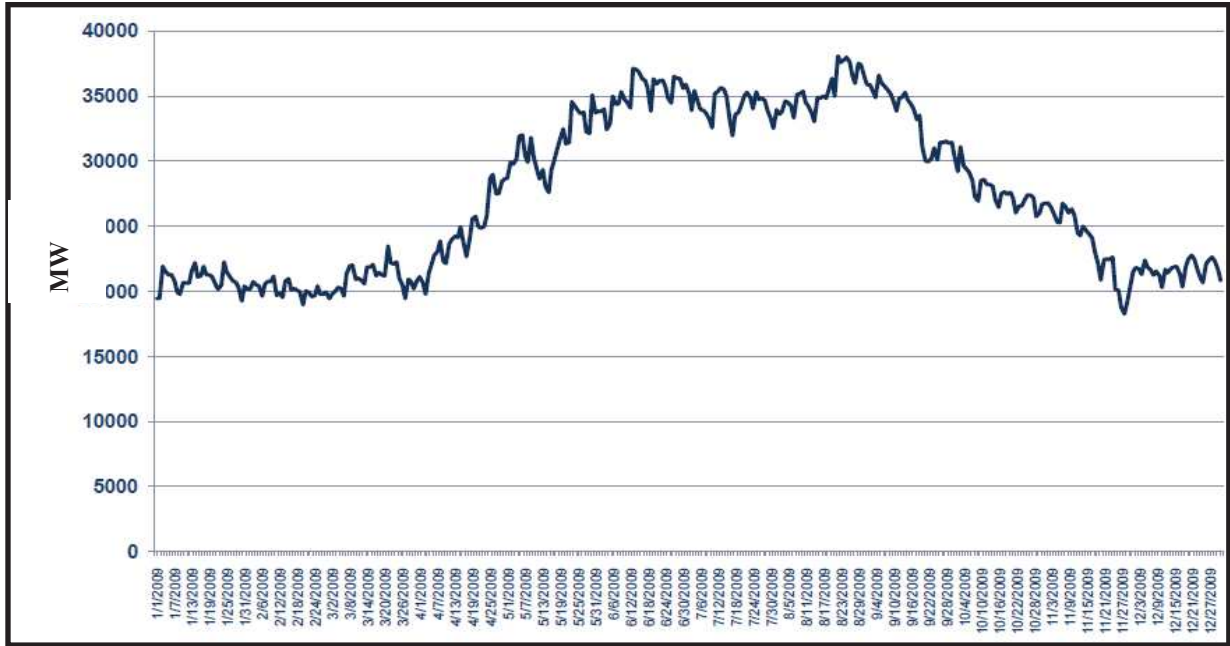


Figure 1-8: Annual load curve for Saudi Arabia in 2009

(Source: Electricity & Co-generation Regulatory Authority)

In figure 1-8 we represent the load curve of Saudi Arabia during year 2009. This demand structure has been used in the model for simulating the current generation mix of the country. As it was mentioned before, the total electricity demand of the country will reach 80GWe in 2020 and 120GWe in 2030 (SEC 2009 and ECRA 2010). Hence, future demand curves considered in the models for the year 2020 and the year 2030 increase proportionally to this demand structure up to the before-mentioned amounts.

The overall demand for electricity in Saudi Arabia has been refined by different seasons. They are defined in Table 1-3.

Model's parameter	Seasonal periods in Saudi Arabia
S1	Summer
S2	Spring and Autumn
S3	Winter

Table 1-3: Seasonal definition

Demand corresponding to each season will be the demand to be met by using the available generation capacity. The reason for which three periods have been defined is the fact that in each period, the load behaviour is quite uniform. This seasonal division is shown in the Figure 1-9.

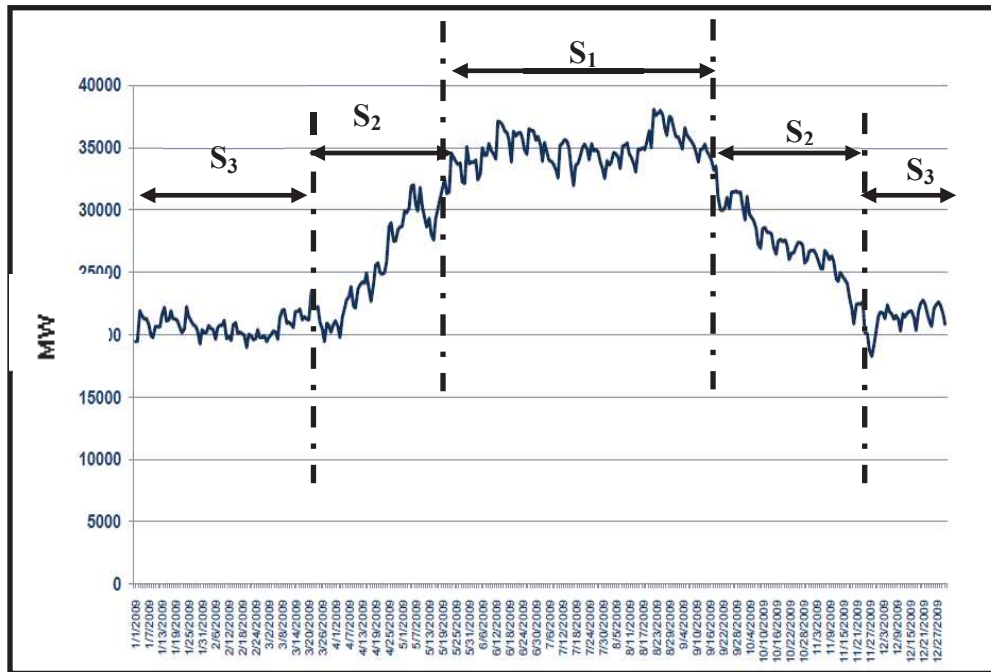


Figure 1-9: Seasonal periods' definition over an annual loading curve of Saudi Arabia's power sector (ECRA 2010)

#### Seasons :

- \* Winter ( $S_3$ ): December, January, February, March
- \* Spring and autumn ( $S_2$ ): April, May, October and November
- \* Summer ( $S_1$ ): June, July, August and September

In Saudi Arabia, periods when electricity demand is the highest correspond to the months of June, July and August and up to the end of September ( $S_1$ ). In our model we presume the same amount of hour for each season ( $S_1$ ,  $S_2$  &  $S_3$ ) which is not far from the reality.

$$S_1 = S_2 = S_3 = \left( \frac{8760}{12} \right) \times 4 = 2920h$$

The demand equation in our GAMS model is as following:

$$demand(season) .. sum((iunit), PUISS(iunit, season)) = g = MCoef. * DEMNET(season);$$

In which the net demand of electricity (times the multiplier coefficient for future national demand for electricity) must be satisfied by the power generated on the grid. Generated power equals the installed capacity multiplied by number of operating hours in each season. More details of the GAMS model could be found in Appendix 1-B.

### **Load Factors and Back-up Plants**

The annual load factor of an electrical power plant is explained by the ratio of the electricity generated by a plant and the theoretical maximum energy that could be produced over the year (8760 hours). For the nuclear and fossil-fuelled units, this annual load factor is simply determined by planned unavailability due to the maintenance or refuelling or shutdowns when the plant is not considered for dispatching. Assuming base-load generation, in this study we applied a generic 85% load factor for our nuclear and fossil-fuel based power units. Nevertheless, for solar sources, the output of the plant is impacted not only by the aforementioned unavailability factors but also by site-specific availability of solar irradiation. In this study, as it was already said in the previous section, we consider the average load factors of 25% and 42% respectively for PV and CSP sites.

Moreover, in an attempt to cover the risk related to the intermittent production of solar power plants, we have introduced in the model a necessary investment in the fossil-fuel power plants that play the back-up role in case of insufficient capacity factor that could happen during peak consumption. In most of the regions around the world, lowest values of capacity factor for the intermittent technologies are observed during peak demand periods. On the contrary, in Saudi Arabia the capacity factor of solar technologies does not vary too much during peak hours because of the climatic characteristics of the country. Peak hours generally take place around 3 p.m. in summer when we have proper shining factor for the solar technologies.

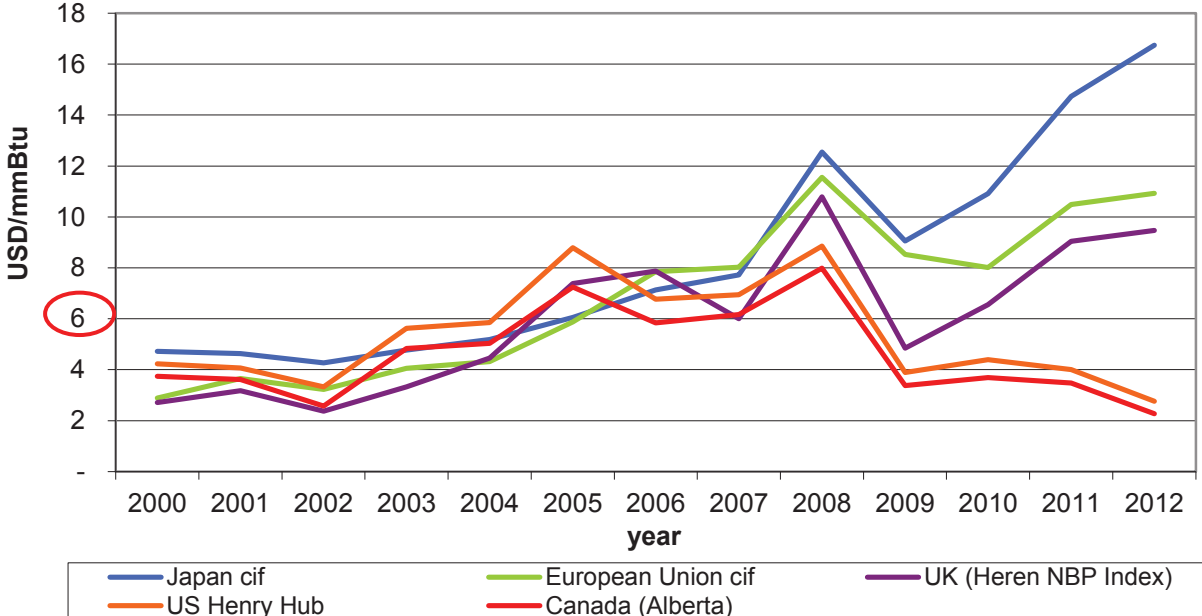
In our model the absence of production from intermittent means is compensated by combined cycle plants and/or gas and fuel turbines which have around 100% of availability (capacity

factor equals to 1) except for the ex-ante planned maintenance. So the total yearly cost of power generation, for the renewable-integrated power mix, includes these back-up costs.

**Fuel Costs**

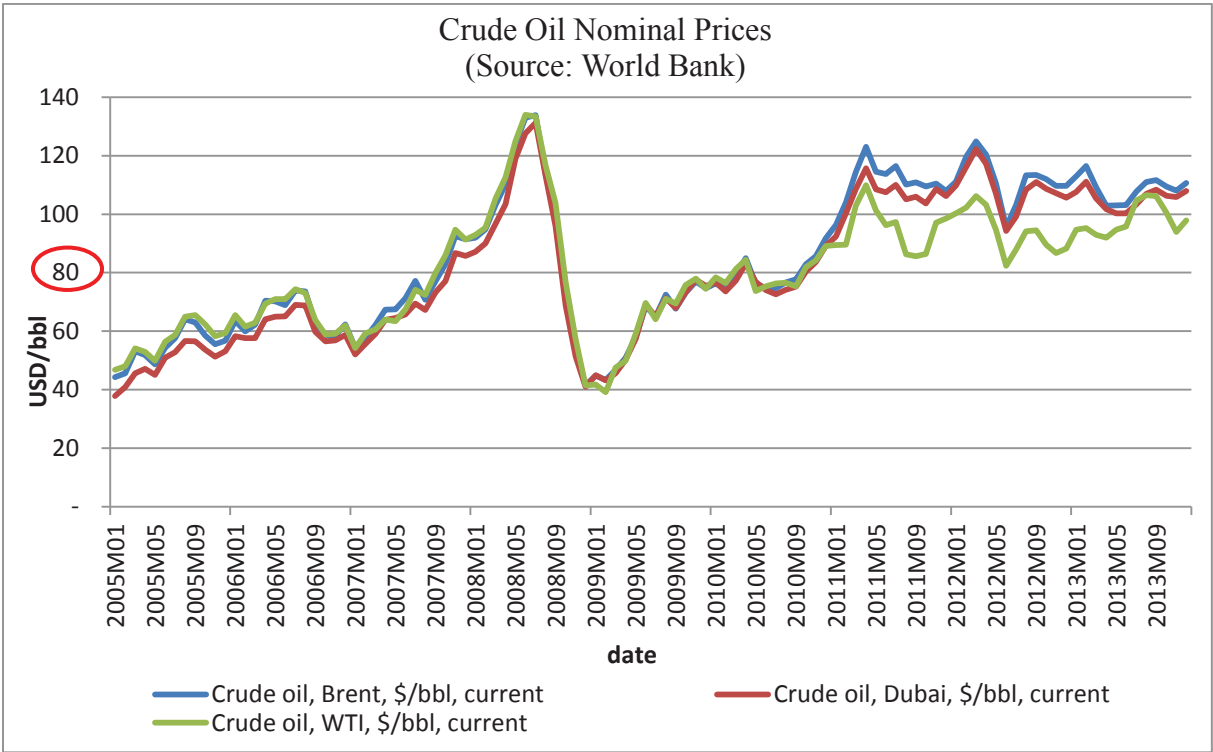
Fuel costs are calculated per MWh on the basis of price information available for gas, oil and uranium (IEA, BP Statistics and World Bank). In the case of gas price, we considered the average price of large gas producing countries like Canada, USA, Australia and Russia (6 \$/MMBtu), where domestic prices of natural gas can decouple from international market prices. This averaged price could be a good representative of international gas price for Saudi power sector, although the real (strongly subsidized) domestic gas price is much lower for the Saudi power producers.

Various world natural gas prices  
(Source:BP Statistics)

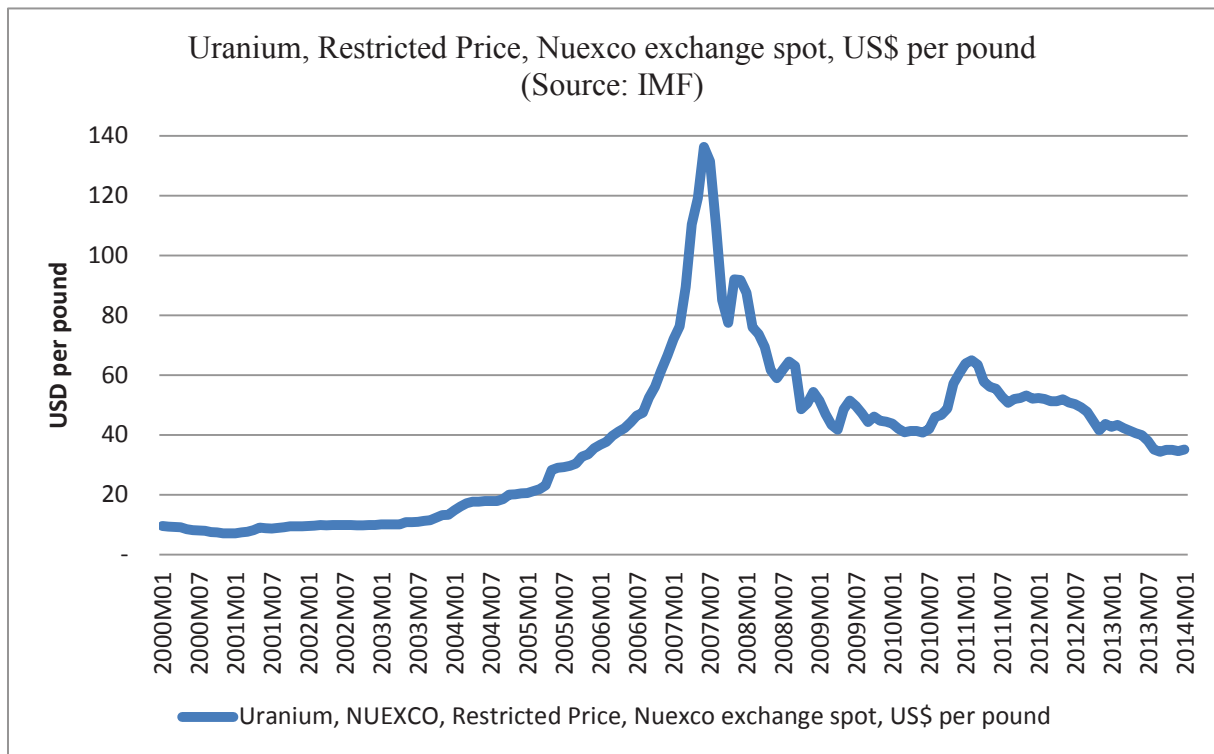




And for oil, Dubai dated average price over the last 4 years has been considered (80 \$/bbl), even if sometimes we use oil products in power generation which are more or less expensive than the crude itself. Despite the fact that in this study we assume stable fuel prices for the matter of simplicity; this should not be considered or interpreted as any sort of prediction of stable energy markets.



In the case of uranium the task is entirely different because the price of  $U_3O_8$  (so-called “yellow cake”) only counts for about 5% of the total cost of power production and therefore any volatility in the price has very small impact on the total cost of electricity generation. Spot-market plays a very limited role for the nuclear fuel (at different stages) and most of the activities are carried out under long term contracts. In the model we assume the nuclear fuel price of 7 \$/MWh until fuel fabrication process, plus 2.5 \$/MWh more for transport, storage and eventually reprocessing and final disposal (IMF).



### Model's Scenarios

In our model we attempt to analyse the future situation of Saudi Arabia generation mix under different scenarios, respectively ten and twenty years forward. To do so, we assume the most probable scenarios for the electric mix of the country for years 2020 and 2030. Then we calculate the total yearly cost of optimal electricity generation for each specific year and scenario. Figure 1-10 illustrates different assumed scenarios integrated to the model. They are constructed based on the information announced and provided by the Saudi authorities in recent years for the most probable future power generation mix (SEC & ECRA 2011).

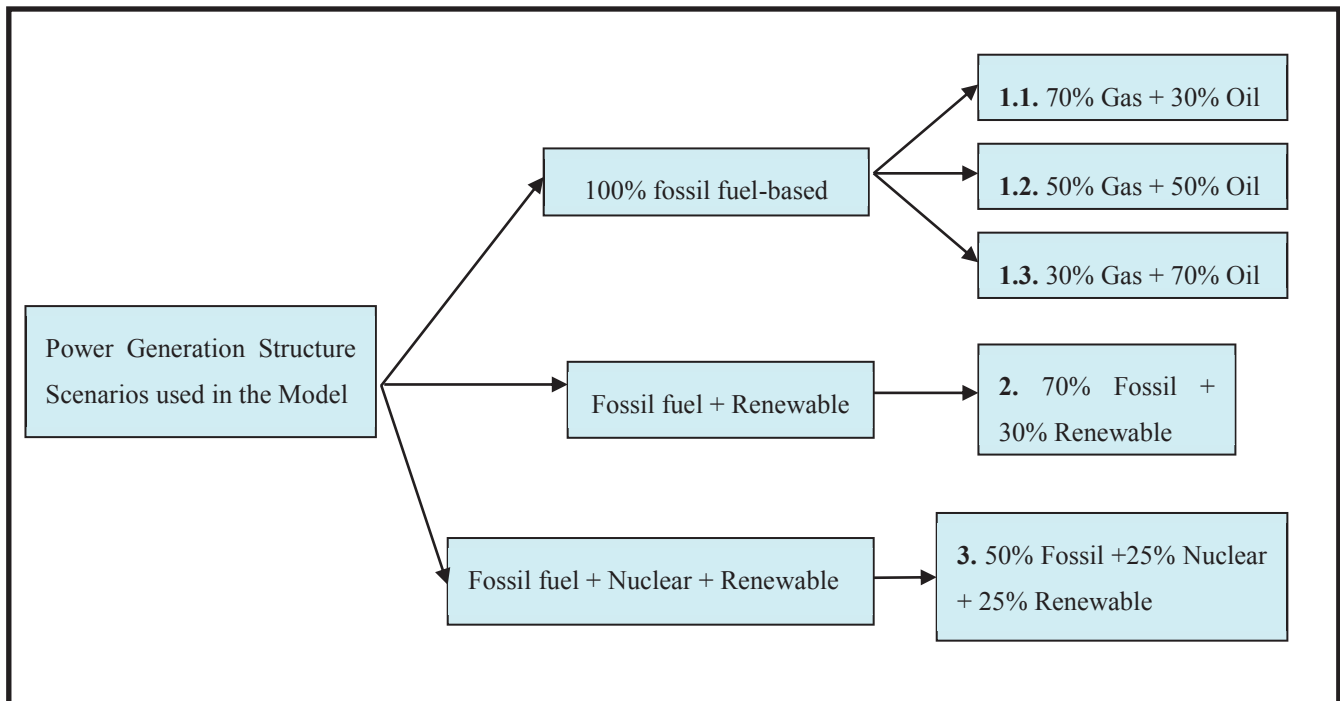


Figure 1-10: Scenarios considered for the electric power generation mix model of Saudi Arabia

Three main scenarios, including three sub-scenarios, have been considered for the future electricity mix of the country. In first scenario, which is our business as usual and most probable scenario, we continue the power generation of Saudi Arabia by using 100% of fossil-based (Oil and Gas) power plants in years 2020 and 2030. Therefore, there is no investment or construction plan for nuclear and renewable energies. Investments only go for oil-based and gas-based thermal power plants. For this scenario we have defined three sub-scenarios which are as following:

Gas oriented mix (1-1): In which we consider 70% of the electricity production from gas-based power plant and the remaining 30% is provided by oil-based plants.

Fifty-fifty fossil fuel mix (1-2): This is our middle case sub-scenario in which half of the power production is provided by gas-based plants and the other half of it by oil-based ones. This scenario is too similar to the current power generation situation of Saudi Arabia.

Oil oriented mix (1-3): Finally, the last assumed sub-scenario is based on the massive usage of fuel power plants. In this scenario 70% of power is generated by Oil-based plants and the remaining part would be satisfied by gas consuming power plants.

Our second scenario for the future mix of the country contains both fossil-based and renewable resources. We assume 30% integration of renewable sources in the total generation mix of Saudi Arabia. Only solar power plants, both PV and CSP, have been integrated to the model due to their remarkable efficiencies under the climatic situation of Saudi Arabia. The rest of the electric power is afforded by the fossil-based (50%Oil and 50%Gas) thermal power plants.

Finally our third scenario contains all the possible resources of electricity generation (Fossil, Renewable & Nuclear). In this scenario, we assume that at least half of the generated power is provided by non-fossil based power plants, both Nuclear and Renewable. The share of each technology in the generation mix is equal to 25% of installed capacity.

**Simulation Results**

To calibrate and verify the reliability of the model, we compared the results of the reference year with the observed data provided by IEA Electricity Information and BP Electricity Generation Statistics. The amount of power production in our base case (reference year 2010) generation mix and those of BP and IEA are shown in table 1-4.

<b>Source</b>	<b><i>Power generation</i></b>
<b>BP Statistics</b>	<i>240 TWh</i>
<b>IEA Electricity Information</b>	<i>240.3 TWh</i>
<b>Model Base Case</b>	<i>239 TWh</i>

Table 1-4: Model's base case result validation for power production in 2010

Thereafter we run the model for all the pre-defined scenarios. Figure 1-11 illustrates the total costs of power generation per year for different structures of generation mix.

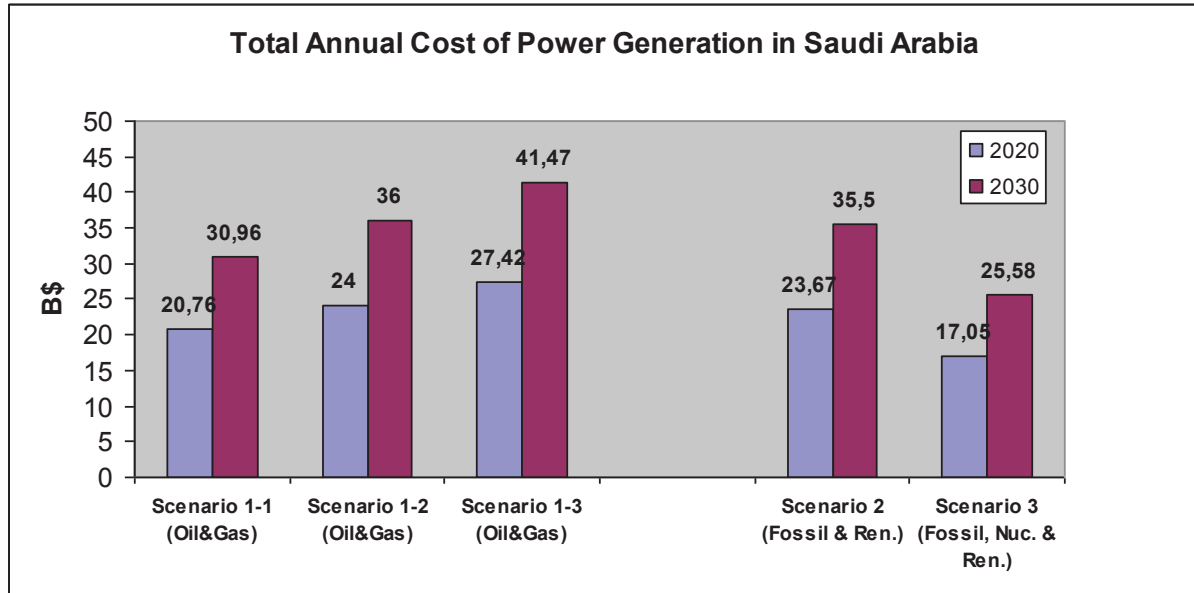


Figure 1-11

The first scenario (and its three related sub-scenarios) shows us the cost of electricity production during years 2020 and 2030 by using only fossil fuel based power plants. The total cost of generation (minimum and optimal cost of-course) increases dramatically when the integration rate of oil rises in the national generation mix.

Moreover, the cost difference between year 2020 and year 2030 also increases when we switch to more oil dependent mixes. The results for scenario 2, in which we consider 30% of renewable share in the national generation mix, are not far from those of scenario 1-2 suggesting 50% of oil-consuming power plants in the system. However, it is essential to state that, this conclusion is only based on the pure economic insight and if we include also environmental externalities then the result would be different and renewable integration will certainly have more success.

Finally the result concerning scenario 3, both nuclear and renewable integration to the national mix, illustrates the dramatic impact of nuclear plants on the total cost of power generation. For instance, the cost difference between scenario 3 and scenario 1-1 (which

consumes mostly gas compare to more expensive oil) has been estimated by the model to be around 3.7 billion dollars in 2020 and even higher in 2030 (5.38 billion USD).

The output of the model for the other variables, such as loaded power on the grid and associated reduced costs are available in the Appendix 1-A (output and solve Summary).

### **Sensitivity and Break-Even Analysis**

In order to perform a reasonable sensitivity analysis, we have chosen to test the impact of changes in the discount rate on a total generation cost calculation. The reason behind this choice is the fact that the discount rate has more significant impact on the generation cost for capital intensive centralized generation units and at the same time it is the most uncertain factor in the case of Saudi Arabia. Oil and gas technologies and their associated O&M and fuel costs are already very well known in Saudi Arabia and therefore we are looking for a factor (which is the discount rate in our study) that can remarkably impact the new power units such as renewable and nuclear ones. Sensitivity analysis over the other underlying parameters of generation cost, such as fuel costs, has also been considered in our study because of their rather non-negligible influence over the total cost of oil and gas power units. In the particular case of solar plants, generally load factor variation has the most important weight in the total cost sensitivity analysis and to a lesser extent the construction cost. However, in the case of Saudi Arabia as the load factor is somehow stable (due to the regional climatic condition and important share of CSP) we focus more on the construction and initial investment costs.

The discount rate that we have considered in our model is equal to 8% based on a set of governmental studies and information regarding investments in power sector in Saudi Arabia (KACARE 2010). Sensitivity analysis has been performed for all the three scenarios. The impact of several discount rates on total annual generation cost for these three scenarios is shown in the Figure 1-12 for discount rates ranging from 5% to 15%.

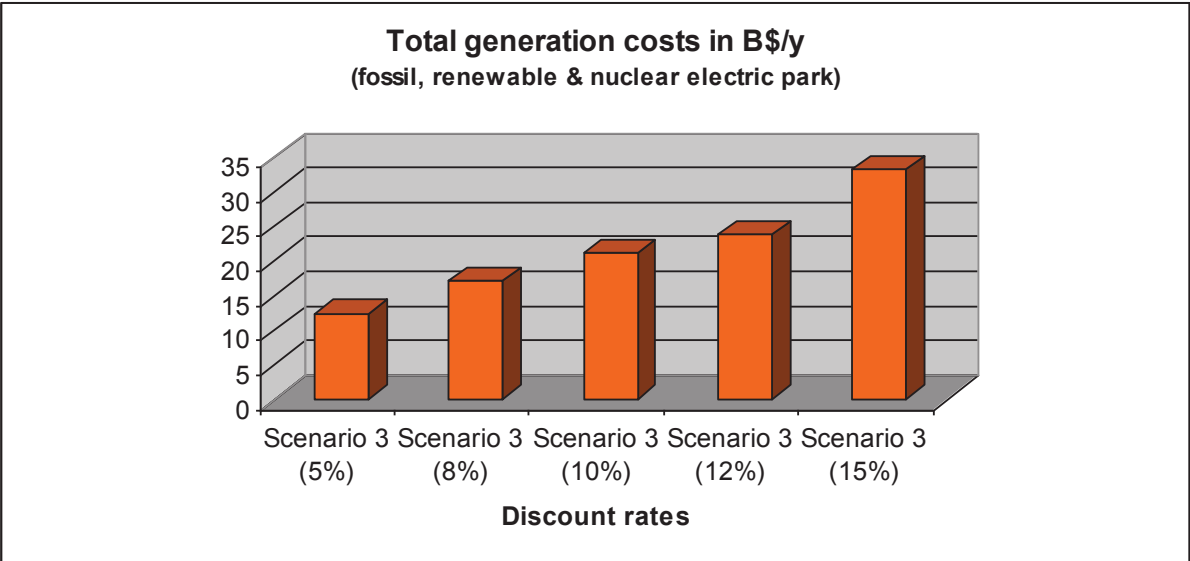
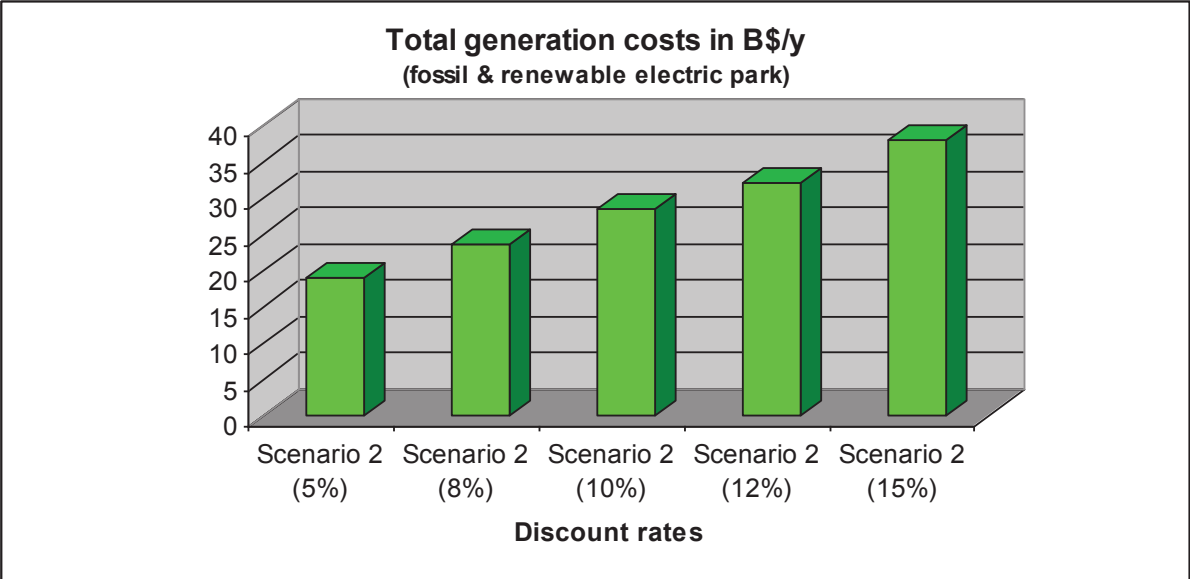
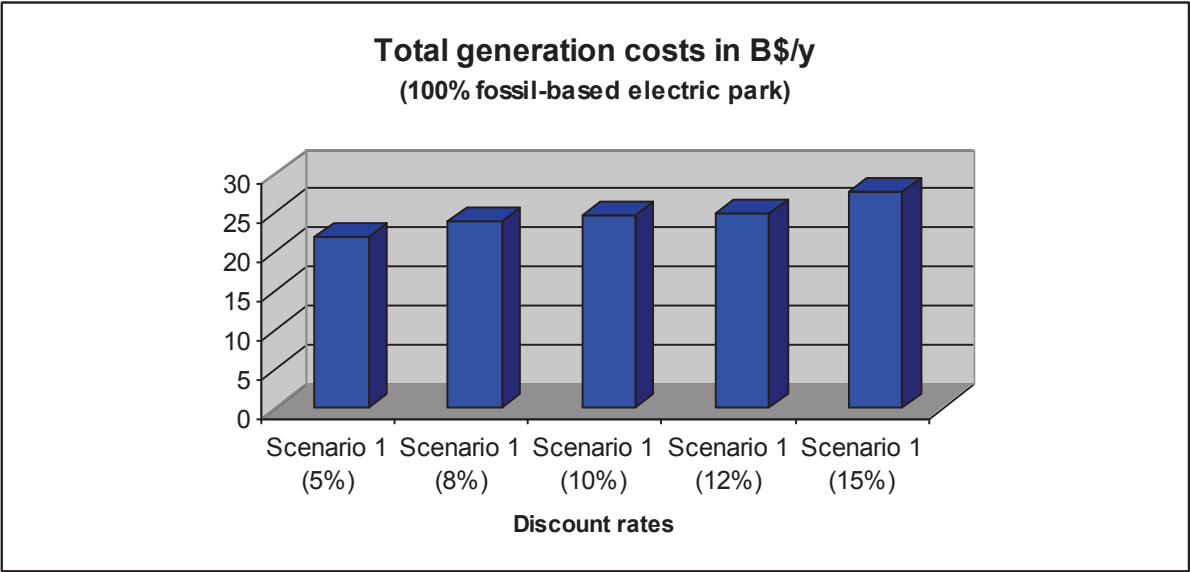


Figure 1-12

Logically, within higher capital cost, the total cost for all scenarios increases. On one hand, we see a relative stability of fossil-based (gas and fuel) power plants cost and therefore their almost insensitivity to cost of capital changes. On the other hand, nuclear power units, in spite of having a lower initial investment cost ratio rather than solar technologies, are the most sensitive units to discount rate changes, too simply because they have much longer construction times than any other power unit. The construction time for a nuclear plant in the model is equal to 5 years while for solar plants is only 1 year. This high sensitivity of nuclear power units compare to solar ones can be easily revealed by comparing the sensitivity results (comparative growth rate of each chart) of the two non-fossil based plants integration scenarios (2 and 3). Therefore, financing structure and capital costs are of significant importance to investments in nuclear capacity.

Break-even analysis has also been performed for aforementioned scenarios at different discount rates (figure 1-13). The outcome will help us to make a more rational (from economic point of view) technology choice for the national power generation. As it is shown in figure 1-13, at the discount rate of 8%, our pure fossil based scenario intersects the 30% renewable penetration scenario. It means that at the discount rates greater than 8%, a fossil-based generation mix is more economic than that of scenario 2. However, scenario 3 (with both nuclear and renewable penetration) remains the most economical solution. This situation continues until the discount rate of 13%. Thereafter, the fossil-based scenario becomes again the best scenario (economically speaking) compare to the other two. It is important to remark that with a higher integration of gas plants into the system, this second break-even point could be pushed even more to the left. In other words, higher percentage of gas power plants in the pure fossil-based national mix will promote the first scenario (under the current gas price assumptions of-course).



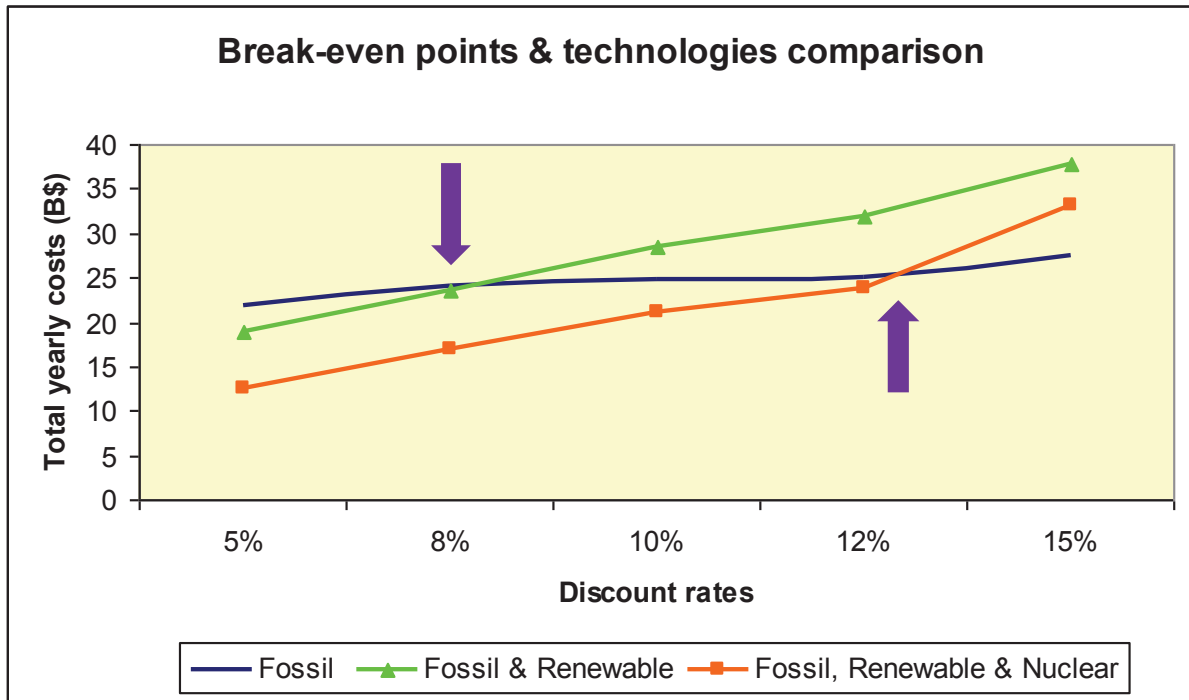


Figure 1-13

There is another interesting observation for our two non-fossil based scenarios at the discount rate of 12%. From this point, the distance between the two scenarios becomes narrower. It shows the fact that after 12% of discount rate, the profitability of scenario 3 over the 2<sup>nd</sup> one becomes less and less significant. It confirms the higher sensitivity of nuclear power plants to discount rates than that of renewable energies such as solar in our case.

Finally, we performed a sensitivity analysis over fuel costs to observe the impacts of fuel costs variation over the investments decision making processes proposed by the model for the year 2020. Figure 1-14 shows the total generation costs' variation and sensitivities to the fuel costs for the three scenarios. For the fuel costs reduction of more than 23%, the 100% fossil-based scenario (the current generation mix structure of Saudi Arabia) becomes the most promising solution, in terms of economic gain, to satisfy the domestic electricity demand of 2020.

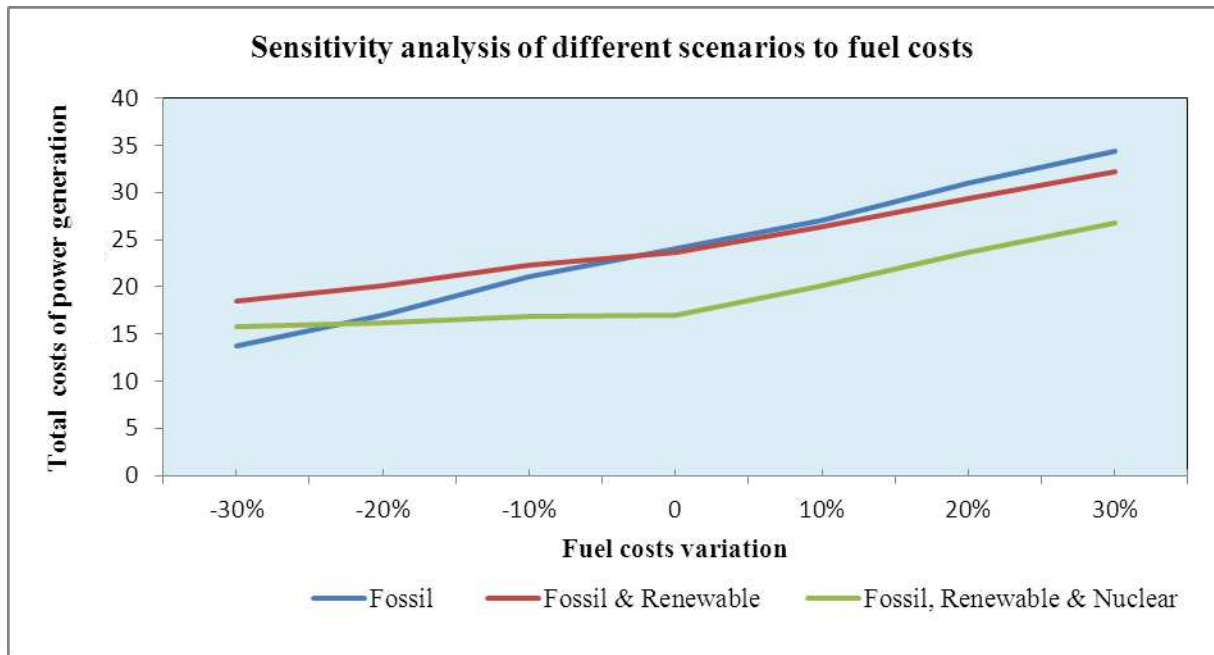


Figure 1-14

The details of the oil price variations' impact over the total power generation cost are shown in the table 1-5. what we notice in the table, is the high sensitivity of 100% fossil-based scenario to the oil price variations. However, it is not really the case for the decarbonized generation mix. This observation becomes even more significant for oil price reduction rather than its increase. For the oil price reduction up to 50%, the total power generation cost could only reduce accordingly up to 6% which indicates the total cost resistance of non-fossil based mix against the price reduction. While in the case of fossil-based generation mix, the total generation cost reduction could attain more than 60% of decrease in its value. Hence, we can conclude that the oil price reduction is highly favourable to the 100% fossil-based power generation mix. As a matter of fact, with oil price reduction of more than 30%, which is equivalent to the oil price of around 55 \$/bbl, it would be very difficult and challenging for the central planner to switch to non-fossil based generation mix from economical point of view.

This is mainly true when we do not include any sort of externalities' cost into the economic evaluation of the entire energy system. However, with oil prices falling below 40 \$/bbl, the non-fossil fuel based generation mix could not compete with the fossil mix at all, even by integrating any measurable externality into the energy system as the total cost of fossil-based mix would become lower than one-third of the non-fossil generation mix.

<b>\$/bbl</b>	<b>Variation</b>	<b>100% Fossil Mix</b>	<b>Fossil, Nuclear &amp; Renewable Mix</b>
		<b>Cost (B\$/y)</b>	<b>Cost (B\$/y)</b>
<b>40</b>	<b>-50%</b>	<b>6,86</b>	<b>15,31</b>
<b>48</b>	<b>-40%</b>	<b>10,35</b>	<b>15,55</b>
<b>56</b>	<b>-30%</b>	<b>14</b>	<b>15,8</b>
<b>64</b>	<b>-20%</b>	<b>17</b>	<b>16</b>
<b>72</b>	<b>-10%</b>	<b>21</b>	<b>16,3</b>
<b>80</b>	<b>0</b>	<b>24,3</b>	<b>16,5</b>
<b>88</b>	<b>10%</b>	<b>26,5</b>	<b>20,1</b>
<b>96</b>	<b>20%</b>	<b>31</b>	<b>24</b>
<b>104</b>	<b>30%</b>	<b>34,4</b>	<b>26,2</b>
<b>112</b>	<b>40%</b>	<b>37,75</b>	<b>29,5</b>
<b>120</b>	<b>50%</b>	<b>41,23</b>	<b>32,6</b>

Table 1-5

In the figure 1-15 we show the total cost of power generation for our fossil and non-fossil generation mix scenarios for various oil prices. The switching oil price of the two scenarios is located somewhere around 61 \$/bb (inside the red rectangle in the below figure). With oil prices below 61 \$/bbl, fossil based scenario would become more economical without any doubt.

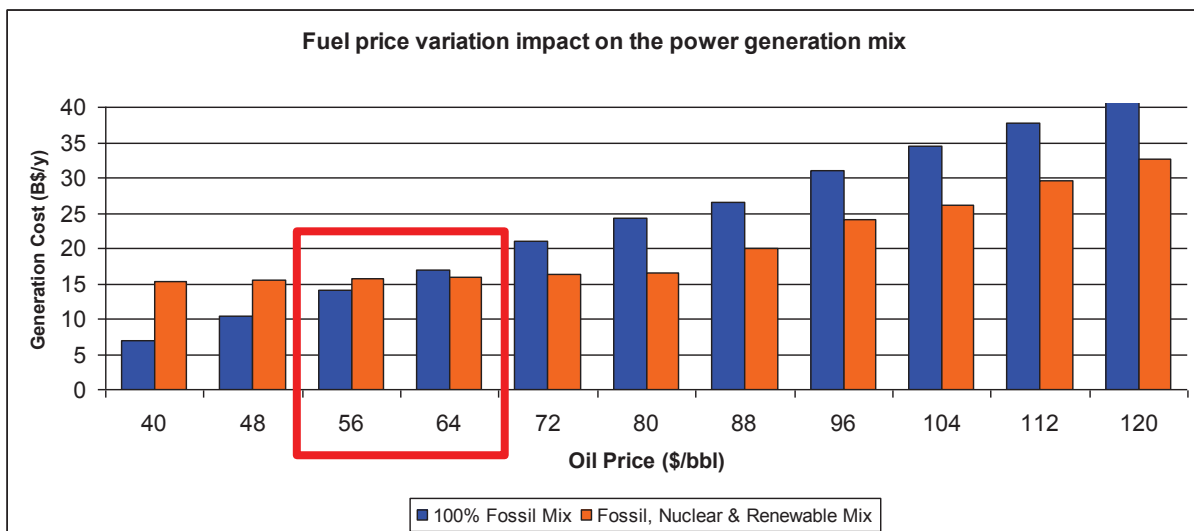


Figure 1-15

This conclusion is valid if we only consider the total cost of power production without taking into the account the revenue coming from the export opportunity of fossil fuels to international markets. As Saudi Arabia can release up to around 2 million barrels per day in the non-fossil scenario, this break-even price of oil (in our case switching price of oil) would equal to almost 50 \$/bbl in the international market.

At this point we should again emphasize on the fact that the long-term decision-making process should absolutely not rely on the short-term fluctuating price of fuels but rather on the long-term or at least medium-term average fuel price. Therefore, based on our average fuel price estimations (already discussed in the previous sections of this chapter), the oil price of 80 \$/bbl could be a reasonable reference for the scenario planning of the power sector in Saudi Arabia.

**Economic Analysis and Interpretation**

Figure 1-16 shows us the important share of oil consumption in the Saudi Arabia's total oil production. For example in 2010, around one third of the total oil consumption went for power generation via fuel power plants.

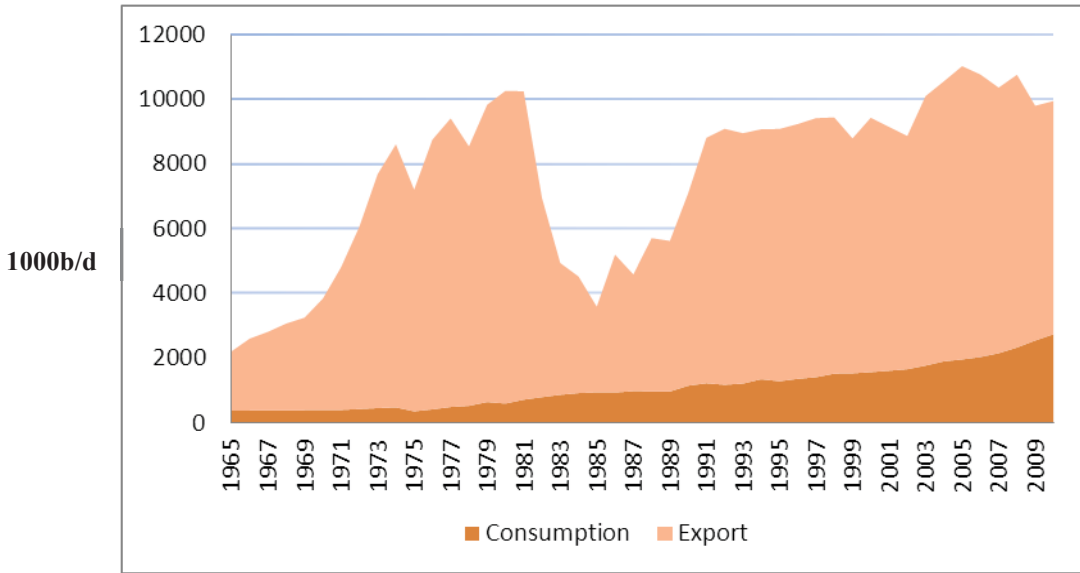


Figure 1-16: Saudi Arabia’s oil production since 1965  
(Source: BP, 2011)

This amount will proportionally increase if Saudi Arabia continues to generate electricity under its current production structure. That means, keep using oil-consuming power plants for 55% of the total electricity generation of the country.

Under the before-mentioned demand increase scenarios, total oil consumption of Saudi Arabia for power generation will reach 1.5 mbd and 2.25 mbd, respectively in 2020 and in 2030. These numbers can become even higher if the share of oil-fired power plants goes beyond 55% of the national generation mix. As a matter of fact, Saudi Arabia can release at least 1mbd of crude oil by decarbonising its power generation. For instance, under scenario 2, (30% of renewable integration into the generation mix) Saudi Arabia will be able to put aside around 1.05 mb per day in 2020. This number could be easily doubled if the generation mix moves toward scenario 3 and even tripled by going beyond 25% of nuclear integration.

Eventually, switching from first group scenarios (1-1, 1-2 & 1-3) to non-fossil fuel based scenarios will not only reduce the generation cost of electricity but will also remarkably increase the oil export revenue of Saudi Arabia.

## Conclusion

The results of the simulations of the power sector in Saudi Arabia shows us that for various scenarios of fossil-based power plant replacement, by both renewable and nuclear ones, we can observe a remarkable cost reduction in the total power generation cost of Saudi Arabia. The same thing does not happen in the case of generation mix extension by using only renewable power plants. For instance, from 2020 Saudi Arabia can reduce by 29%, its yearly power generation costs by integrating up to 50% of non-fossil sources (nuclear and renewable) into its generation mix. This amount could be even doubled from 2030 under the same scenarios of generation mix structure. To a lesser extent, this is also true for 50% share of pure renewable energies (solar units) without any nuclear power plant in the Saudi energy system. From 2020 up to 2030, Saudi Arabia can enjoy a yearly cost reduction of 3%, by switching from 100% fossil-based power mix to 30% share of renewables in the national power generation mix.

Moreover, by exporting the amount of oil extracted out of the generation mix (released thanks to the fuel power plant replacement) Saudi Arabia can make massive financial and political benefits. Financial benefits, not only because of the considerable reduction in the total generation cost of electricity, but also, by raising the amount of crude oil export. Political benefits, due to an increase in their spare capacity of oil production (providing more flexibility for Saudi Arabia in terms of oil production) and consequently, an increase in its role in the OPEC and international oil market.

Besides, decarbonisation of the national electricity generation mix and consequently construction of more centralised non-fossil power units (CSP and especially nuclear plants) will contribute a lot to the more efficient water desalination of the country which is also a very vital energy-consuming sector along with the power generation.

Last but not the least, as it is already mentioned at the very beginning of this study, we did not perform any cost analysis regarding CO<sub>2</sub> emissions resulted from power generation in Saudi Arabia, as the government has not yet released any sort of concrete plan or intention regarding this issue. *Vis-à-vis* CO<sub>2</sub> emissions reduction, the main focus of the Saudi government is rather on the oil sector and efforts targeting at more sustainable methods of primary oil production together with enhanced oil recovery processes. This is also the policy adopted by the Iranian government elaborated in the third chapter of this work.

Furthermore, the economic benefits of the decarbonisation trend of the Saudi power generation is that much weighty which will make the potential economic benefits of any other externality, including cumulated CO<sub>2</sub> cost reductions, completely negligible in comparison.

At the end we should emphasize on the fact that these benefits could be realized only in the case that we give an opportunity cost to the fuel that we use in the power plants. Without this hypothesis (e.g. cheaper fuel cost compare to the international market price due to subsidies) the major part of the variable cost will be vanished in the model and the benefits would become negligible. If Saudi Arabia continues with the same generation mix for its national power generation, 1 million barrels of oil equivalent per day would be needed in 2020 so as to satisfy the 80 GWe of domestic electricity demand. On the contrary and according to the model's result, Saudi government can release at least 50% of this amount (equivalent to 0.5 Mb/d) for export.

## Appendix 1-A

### *The values of the model's variables (output) for the scenario 3*

#### Power Units

TH: Thermal Fuel Power plant,

CG: Combined Cycle Gas

NU: Nuclear Power Plant

RE: Renewable Solar Plants (combined PV & CSP)

#### Seasons

S1: Season 1, Summer

S2: Season 2, Spring & Autumn

S3: Season 3, Winter

	Level (MW)	Reduced cost (US\$/MWh)
TH,s1	27000	0
TH,s2	0	30
TH,s3	0	30
CG,s1	27000	0
CG,s2	24000	0
CG,s3	16000	0
NU,s1	36000	0
NU,s2	36000	0
NU,s3	32000	0
RE,s1	15000	0
RE,s2	15000	0
RE,s3	15000	0



Demand equation at the optimum for each season		
	Level (MW)	Shadow value (US\$/MWh)
s1	1.0500E+5	303,3
s2	75000.000	40,0
s3	63000.000	40,0

**SOLVE SUMMARY (model for the scenario 3)**

```

2 8 8
2 8 9 MODEL El ec OBJECTI VE z
2 9 0 TYPE LP DI RECTI ON M NI M ZE
2 9 1 SOLVER CPLEX FROM LI NE 117
2 9 2
2 9 3 **** SOLVER STATUS 1 Nor mal Compl et ion
2 9 4 **** MODEL STATUS 1 Opti mal
2 9 5 **** OBJECTI VE VALUE 222679200000. 0000
2 9 6
2 9 7 RESOURCE USAGE, LI M T 0.156 1000.000
2 9 8 ITERATI ON COUNT, LI M T 8 2000000000
2 9 9
3 0 0 I B M I L O G C P L E X 24.4.1 r50296 Released Dec 20, 2014 WEI x86 64bit/MS
W ndows
3 0 1 Cpl ex 12.6.1.0
3 0 2
3 0 3 Space for names approxi mately 0.00 Mb
3 0 4 Use option 'names no' to turn use of names off
3 0 5 LP status(1): opti mal
3 0 6 Cplex Time: 0.06sec (det. 0.04 ticks)
3 0 7 Opti mal soluti on found.
3 0 8 Objective : 222679200000.000000
3 0 9
3 1 0
3 1 1 LOWER LEVEL UPPER MARGI NAL
3 1 2
3 1 3 ---- EQU cost . . . 1.000
3 1 4
3 1 5 ---- EQU suppl y
3 1 6
3 1 7 LOWER LEVEL UPPER MARGI NAL
3 1 8
3 1 9 TH. s1 -I NF . . -6.813E+5
3 2 0 TH. s2 -I NF -2.700E+4 . .
3 2 1 TH. s3 -I NF -2.400E+4 . .
3 2 2 CG. s1 -I NF . . -7.689E+5
3 2 3 CG. s2 -I NF -3000.000 . .
3 2 4 CG. s3 -I NF -8000.000 . .
3 2 5 NU. s1 -I NF . . -8.565E+5
3 2 6 NU. s2 -I NF . . -8.760E+4
3 2 7 NU. s3 -I NF . . -8.760E+4
3 2 8 RE. s1 -I NF . . -8.857E+5
3 2 9 RE. s2 -I NF . . -1.168E+5
3 3 0 RE. s3 -I NF . . -1.168E+5
3 3 1
3 3 2 ---- EQU demand
3 3 3
3 3 4 LOWER LEVEL UPPER MARGI NAL
3 3 5
3 3 6 s1 1.0500E+5 1.0500E+5 +I NF 8.8573E+5
3 3 7 s2 75000.000 75000.000 +I NF 1.1680E+5
3 3 8 s3 63000.000 63000.000 +I NF 1.1680E+5
3 3 9
3 4 0 ---- EQU capaci ty
3 4 1
3 4 2 LOWER LEVEL UPPER MARGI NAL
3 4 3
3 4 4 TH. s1 27000.000 27000.000 27000.000 -6.813E+5
3 4 5 TH. s2 27000.000 27000.000 27000.000 EPS
3 4 6 TH. s3 24000.000 24000.000 24000.000 EPS
3 4 7 CG. s1 27000.000 27000.000 27000.000 -7.689E+5
3 4 8 CG. s2 27000.000 27000.000 27000.000 EPS
3 4 9 CG. s3 24000.000 24000.000 24000.000 EPS
3 5 0 NU. s1 27000.000 27000.000 27000.000 -8.565E+5
3 5 1 NU. s2 27000.000 27000.000 27000.000 -8.760E+4

```

```

3 5 2 NU. s3 24000.000 24000.000 24000.000 -8.760E+4
3 5 3 RE. s1 . . . -8.857E+5
3 5 4 RE. s2 . . . -1.168E+5
3 5 5 RE. s3 . . . -1.168E+5
3 5 6
3 5 7 LOWER LEVEL UPPER MARGI NAL
3 5 8
3 5 9 ---- EQU i nv1 30000.000 30000.000 +I NF 6.0103E+6
3 6 0
3 6 1 ---- VAR Pui ss Power l oaded on the grid
3 6 2
3 6 3 LOWER LEVEL UPPER MARGI NAL
3 6 4
3 6 5 TH. s1 . 27000.000 +I NF .
3 6 6 TH. s2 . . +I NF 87600.000
3 6 7 TH. s3 . . +I NF 87600.000
3 6 8 CG. s1 . 27000.000 +I NF .
3 6 9 CG. s2 . 24000.000 +I NF .
3 7 0 CG. s3 . 16000.000 +I NF .
3 7 1 NU. s1 . 36000.000 +I NF .
3 7 2 NU. s2 . 36000.000 +I NF .
3 7 3 NU. s3 . 32000.000 +I NF .
3 7 4 RE. s1 . 15000.000 +I NF .
3 7 5 RE. s2 . 15000.000 +I NF .
3 7 6 RE. s3 . 15000.000 +I NF .
3 7 7
3 7 8 ---- VAR I nv
3 7 9
3 8 0 LOWER LEVEL UPPER MARGI NAL
3 8 1
3 8 2 TH . . +I NF 43800.000
3 8 3 CG . . +I NF 43800.000
3 8 4 NU . 10000.000 +I NF .
3 8 5 RE . 30000.000 +I NF .
3 8 6
3 8 7 ---- VAR CAPAVAI BLE
3 8 8
3 8 9 LOWER LEVEL UPPER MARGI NAL
3 9 0
3 9 1 TH. s1 . 27000.000 +I NF .
3 9 2 TH. s2 . 27000.000 +I NF .
3 9 3 TH. s3 . 24000.000 +I NF .
3 9 4 CG. s1 . 27000.000 +I NF .
3 9 5 CG. s2 . 27000.000 +I NF .
3 9 6 CG. s3 . 24000.000 +I NF .
3 9 7 NU. s1 . 36000.000 +I NF .
3 9 8 NU. s2 . 36000.000 +I NF .
3 9 9 NU. s3 . 32000.000 +I NF .
4 0 0 RE. s1 . 15000.000 +I NF .
4 0 1 RE. s2 . 15000.000 +I NF .
4 0 2 RE. s3 . 15000.000 +I NF .
4 0 3
4 0 4 LOWER LEVEL UPPER MARGI NAL
4 0 5
4 0 6 ---- VAR z -I NF 2.227E+11 +I NF
4 0 7
4 0 8 z cout
4 0 9
4 1 0
4 1 1 **** REPORT SUMMARY : 0 NONOPT
4 1 2 0 I NFEASI BLE
4 1 3 0 UNBOUNDED
4 1 4
4 1 5
4 1 6 EXECUTI ON TI ME = 0.016 SECONDS 2 MB 24.4.1 r50296 WEX-WEI
4 1 7

```

4 1 8  
4 1 9 USER: 10 User License S141201:0912AO-WN  
4 2 0 RUEIL - Magasin General DC346  
4 2 1 License for teaching and research at degree granting institutions  
4 2 2  
4 2 3  
4 2 4 \*\*\*\* FILE SUMMARY  
4 2 5  
4 2 6 Input  
C:\Users\far noosa\Documents\Elect ricité\Resear ch\Thesi s\Saudi \Mdel s\  
4 2 7 Saudi Gen Structure - 2030- OI 25% Gas25% - 25%Nuc- 25%Ren.gms  
4 2 8 Out put C:\User s\far noosa\Document s\cogen\Saudi Gen Structure - 2030-  
OI 25% G  
4 2 9 as25% - 25%Nuc- 25%Ren.l st

## Appendix 1-B

### *Saudi Arabia Power Generation Mix Model in GAMS*

```
2 * Electricity Generation Model
3 *
4 * Saudi Arabia national power structure
5 *
6 *
7 * Power plants
8 *
9 Set i unit power plant
10 /TH Thermal Fuel Power plant,
11 CG Combined Cycle Gas
12 NU Nuclear Power Plant
13 RE Renewable Solar Plant /;
20
21
22 Set season /s1, s2, s3/;
23 * For solar the capacity has been doubled because of 50% availability
24
25 Parameter capi ni (i unit) /
26 TH 30000
27 CG 30000
28 NU 30000
29 RE 0 /;
30
31 Table di spo(i unit, season)
32
33 S1 S2 S3
34 TH 0.9 0.9 0.8
35 CG 0.9 0.9 0.8
36 NU 0.9 0.9 0.8
37 RE 0.5 0.5 0.5
38 ;
39
40 Parameter capaef f(i unit, season);
41
42 LOOP(i unit,
43 LOOP(season,
44 capaef f(i unit, season)=capi ni (i unit)*di spo(i unit, season);
45 ));
46
47 Parameter demel ec(season) /
48
49
50 S1 35000
51 S2 25000
52 S3 21000
53 /;
54 parameter dur ee(season) /
55
56 S1 2920
57 S2 2920
58 S3 2920
59 /;
60 *
61
62 Parameter demet (season);
63 loop(season,
64 demet (season)= demel ec(season) ;
65 );
66
67 * Fixed cost ($/MWh)
68
69 Parameter f cost(i unit) /
70 TH 25
71 CG 28
72 NU 35
```

```

7 4 RE 250
7 5 /;
7 6 *
7 7 LOOP(i unit ,
7 8 fcost(i unit )=8760*fcost(i unit ));
7 9 *
8 0 * variable cost ($/MWh)
8 1 Parameter vcost(i unit) /
8 2
8 3 TH 70
8 4 CG 40
8 5 NU 10
8 6 RE 0
8 7 /;
8 8
8 9 Variables
9 0 Pui ss(i unit , season) Power loaded on the grid
9 1 Inv(i unit)
9 2 CAPAVAI BLE(I UNI T, SEASON)
9 3 z c o u t ;
9 4
9 5
9 6 Positive Variables Pui ss, i nv, capavai ble ;
9 7
9 8 Equat ions
9 9
1 0 0 cost
1 0 1 suppl y(i unit , season)
1 0 2 demand(season)
1 0 3 capaci ty(i unit , season)
1 0 4 i nv1
1 0 5 ;
1 0 6
1 0 7 cost ..
z=e=sum(i unit , season), vcost(i unit)*PUI SS(i unit , season)*dur ee(season)»
)+
1 0 8 sum(i unit , season), fcost(i unit)*i nv(i unit));
1 0 9
1 1 0 suppl y(i unit , season) .. PUI SS(i unit , season) =I =
CAPAVAI BLE(i unit , season);
1 1 1
1 1 2 demand(season) ..
sum(i unit , PUI SS(i unit , season))=g=3*DEMNET(season);
1 1 3
1 1 4 capaci ty(i unit , season) ..
CAPAVai ble(i unit , season)=e=( CAPI NI (i unit )+i nv(i unit »
))*di spo(i unit , season);
1 1 5 i nv1 .. i nv(' RE' ) =g= 30000;
1 1 6 Model El ec /all /;
1 1 7 Solve El ec usi ng Ip mi ni mi zi ng z ;

```

## **Appendix 1-C**

### ***Basic concepts of linear programming***

Since at least the time of Adam Smith and Cournot, economic theory has been concerned with maximum and minimum problems. Modern “neoclassical marginalism” represents the result of this interest. In comparatively recent times, mathematicians concerned with the complex problems of internal planning in the US Air Force and other large organizations have developed a set of theories and procedures closely related to the maximization problems of economic theory. Since these procedures deal explicitly with the problem of planning the activities of large organizations, they are known as “linear programming”. The mathematical definition of linear programming is very simple. It is the analysis of the problems in which a linear function of a number of variables is to be maximized (or minimized) when those variables are subjected to a number of restraints in the form of linear inequalities. The difficulties starts to appear when we raise the question of applying various methods derived from linear programming to real economic problems. Notice that the word “linear” occurred two times in stating the mathematical definition of linear programming. The U-shape cost curves, the gently curving isoquants, and the nests of indifference lines on which so much of economic theorizing depends seem to stand in the way of expressing meaningful economic problems in terms of strictly linear relationships.

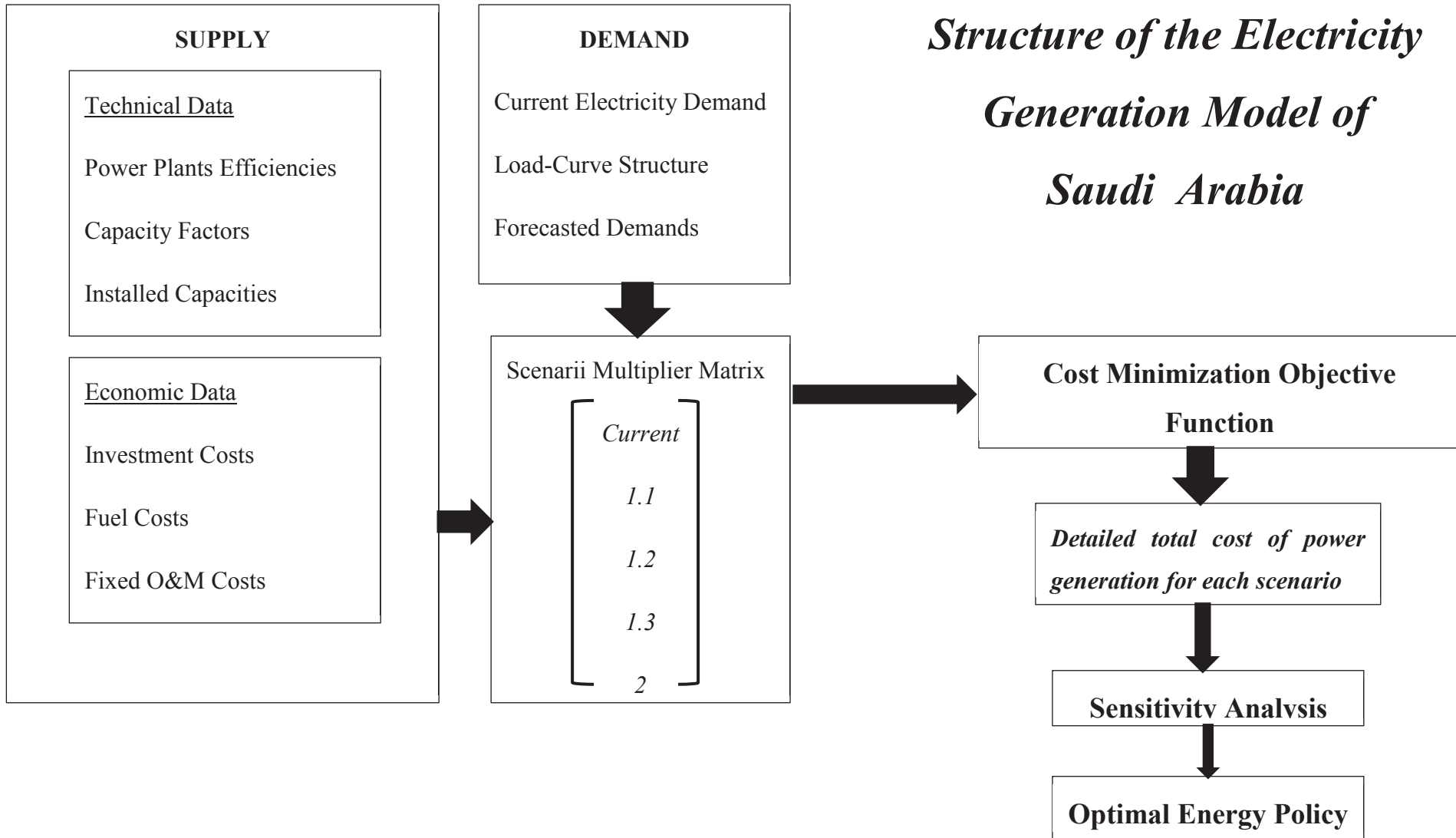
### ***The dual of the problem***

We have already mentioned that linear programming is based on a mathematical problem. It happens that mathematical linear-programming problems come in pares; every mathematical linear-programming problem is intimately related to another problem called its “dual”. This statement would be no more than an interesting mathematical curiosity if it were not for the fact that if an economic problem can be formulated as a linear-programming problem, then there will generally be a related economic problem that corresponds to the dual. These facts are not intuitively evident, and, indeed, it took a while after linear programming had been discovered for the dualism feature to be recognized and appreciated. But they should not be surprising to an economist who, after all, is familiar with the fact that resource allocation and pricing are two aspects of the same problem. An economist would expect that since linear programming solves the allocation problem, it would solve the pricing problem also, and this,

in essence, is what the dualism property consists in. In the last chapter we will discuss more in details the real application of this dualism property to show the optimal value of power pricing in each generation mix. Thereafter, these prices will be compared to those tariffs imposed by the regulators and/or central planners.



# Structure of the Electricity Generation Model of Saudi Arabia



**Chapter 2: On the De-carbonization of Electricity Generation in Egypt**

## Résumé

L'Egypte est le plus grand producteur de pétrole non-OPEP et le deuxième plus grand producteur de gaz naturel en Afrique. La diminution de la production de pétrole et la baisse des réserves au cours de la dernière décennie ont été compensées par une croissance remarquable du secteur du gaz naturel à la fois pour la consommation intérieure et l'exportation. Au cours des dix dernières années, l'Egypte est devenue un producteur de gaz important et un fournisseur stratégique pour l'Europe. En outre, le gaz naturel représente environ 80 % du mix électrique Egyptien. Le taux d'électrification du pays en 2009 était d'environ 99,6%, parmi les plus élevés dans l'ensemble du continent. Dans ce chapitre, nous analysons la structure de production d'électricité actuelle et future du pays à travers un modèle de programmation linéaire dynamique. Nous effectuons une analyse ascendante (*bottom-up*) des coûts afin de déterminer les moyens les plus rentables de production d'électricité en tenant compte de l'intégration et de la croissance des ressources alternatives non-fossiles comme l'énergie solaire, éolienne et nucléaire dans le parc électrique du pays. Enfin, les impacts socio-économiques des modifications du mix sont analysés. Notre analyse de coût, d'investissement et de la sensibilité du mix actuel et futur de l'Egypte montre l'infaisabilité (du point de vue économique) d'être entièrement dépendant des réserves de combustibles fossiles nationales afin de répondre à la demande d'électricité. Par conséquent, une stratégie de production d'électricité basée sur une intégration progressive de l'énergie nucléaire et renouvelable est suggérée. Un mix de production d'électricité, basé sur une combinaison optimale des ressources fossile, nucléaire, hydraulique et des autres énergies renouvelables est considéré comme le moyen le plus approprié pour la production d'électricité en Egypte.

Mots-clés: Secteur Electrique; Egypte; Optimisation ; Sensibilité

## **Abstract**

Egypt is the largest non-OPEC oil producer and the second largest gas producer in Africa. Decreases in oil production and depletion in related reservoirs over the last decade have been compensated by a remarkable growth of the natural gas sector for both internal consumption and export. Over the past ten years, Egypt has become an important gas producer and a strategic gas supplier for Europe. Moreover, natural gas represents around 80 per cent of the Egyptian power sector mix. The country's electrification rate in 2009 was around 99.6 per cent which is among the highest in the whole continent. In this study, we analyse the current and future power generation situation of the country through a dynamic linear analysis approach. We will perform a bottom-up cost analysis in order to determine the most cost-effective ways of power production by taking into account the integration and growth of the other alternative (non-fossil based) resources such as solar, wind and nuclear into the power generation mix of the country. Finally, the socio-economic impacts of these generation-mix modifications will be analysed. Our cost, investment and sensitivity analysis of the Egyptian's current and future power generation mix and demands demonstrate the unfeasibility (from an economic point of view of course) of being entirely dependent on national fossil fuel reserves so as to meet the electricity generation needs of the country. Therefore, a power generation strategy based on a gradual integration of nuclear and renewable is suggested. A power generation mix, based on an optimal choice of fossil, nuclear, hydraulic and other renewables, is considered to be the most appropriate way of electricity production in Egypt.

Keywords: Power Sector; Egypt; Optimisation; Sensitivity

## **Introduction**

Over the past decade, Egypt had solid economic growth due to its rising exports and investment and also its strong national consumption. Energy sector has been highly interconnected with economic activity of the country. Most of the energy demand growth came from growing industrial production and robust population expansion. Energy demand growth has also been promoted by the governmental subsidies coming from exports revenue (mainly hydrocarbon resources). Unfortunately this subsidization policy contributed a lot to fiscal deficit of the country. Recently government has announced several times the suppression of these subsidies. No action has been taken place regarding this issues until now and it seems that nothing will be realized (at least in the short-term future) due to social events and uncertainties that the country is currently facing with following the Arab Spring and recent socio-political movements. Socio-political uncertainties will definitely affect and slow down the demand growth of Egypt. Hence, Egypt economic growth will be tightened specially in high energy-intensive industries and tourism which are the main contributors to the country's economy.

In 2001, after Hosni Mubarak removal from power, Freedom & Justice Party (run by Muslim Brotherhood) came into power. Their main policy was the reduction of social inequality (which was the key driver of the 2011 uprising) in the country but their economic plan and policy was not yet very clear. Despite these new flourished uncertainties, an energy demand growth is expected (at least in the medium and long terms) due to the population growth and industrial developments. Figure 2-1 shows the United Nations forecast of the Egyptian population for different categories of age.

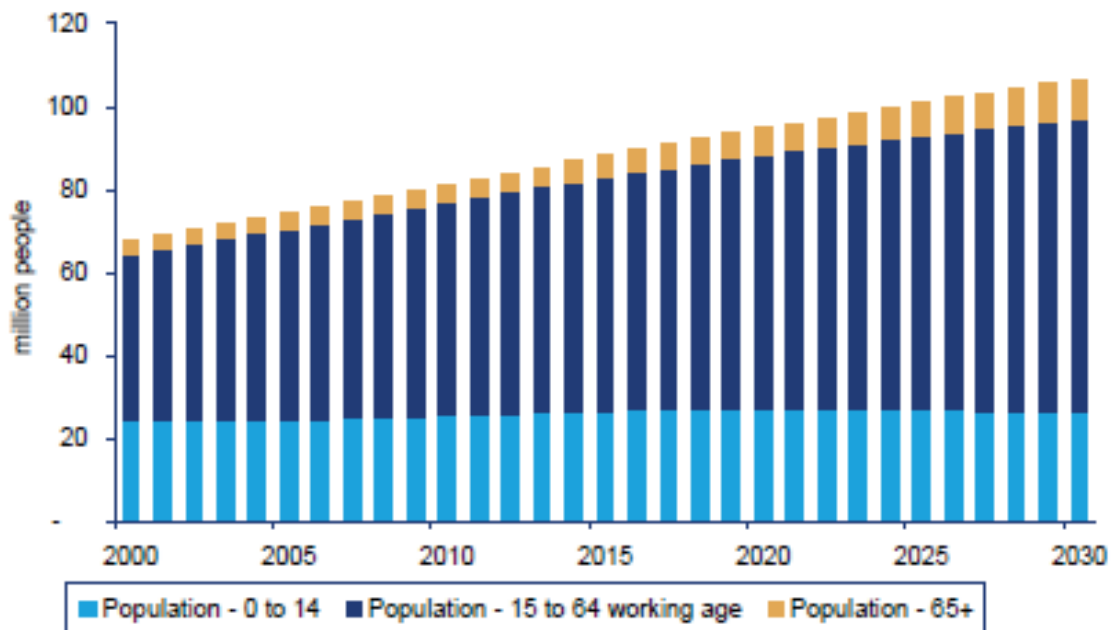


Figure 2-1: Egypt population by age from 2000 to 2030

(Source: United Nations, World Population Prospects: The 2010 Revision)

In 2010, the GDP of the country was around 160 billion US dollars. Service sector accounts for almost 50% of this number with tourism sector as a main contributor. Industrial sector comes after and accounts for approximately 40% of the GDP and the rest goes for agriculture.

Egyptian economy was among the best performing ones between developing countries until 2009 great recession. Thereafter growth damped and slow down mainly because of foreign donation contraction, mostly coming from US, UK and UAE. Egypt experienced its lowest growth of only 1.8% in 2011 (it was 5.1% in 2010), lowest since 1990. As mentioned before, this decrease of growth is essentially driven by Arab Spring events, lower tourism and foreign investment and domestic consumption.

Egypt's highest export revenue comes from natural gas. However, its production is slowing down largely because of the lack of foreign investments (notably from International oil Companies). This production decline will also impact the petrochemical industry fed with natural gas as raw material. Natural gas is the key fuel in Egypt, especially in industry and power sector which is the largest energy consumer sector of the country.

## **Energy and Environmental Policy of Egypt**

Egyptian Ministry of Planning defined the energy strategy of the country by issuing its 6th Five Year Plan (2007-2012). The plan mostly included the investment plans for Electric Power, Oil and Natural Gas industry. Energy efficiency improvements, security of supply and willingness to adopt nuclear technology were also considered as chief strategic targets. Oil and gas sector promotion, consist mainly efforts targeting the expansion and intensification of the exploration activities and completion of the 20-year 10 billion dollar Petrochemicals Master Plan (lunched in 2002 for constructing 24 petrochemical units across the country by the end of 2022). And the strategy for the power sector aims to improve efficiency, promote renewable energies and security of supply for all sectors, encourage the development of grid in rural regions and facilitate more interconnection with neighbouring nations. This 5-year plan has been revised and discussed in 2011 again but no official strategy has been yet released. However, most probably increasing focus on export maximizing, upstream investment incentives and ensuring demand satisfaction will be the key components.

Egypt was first Arab nation signed the Kyoto protocol in 1999. From then Egypt is seeking to diversify its current energy mix by increasing usage of renewable energy sources such as hydro, wind and solar. The Renewable Energy Expansion Plan, adopted in 2008, sets target for renewables sources to reach 20% of total domestic energy supply by the year 2020. 12% will be provided by wind and hydro. However, at the moment there is no reliable support scheme (such as feed-in tariffs or feed-in premiums) in place for the promotion of renewable sources. The total energy related CO<sub>2</sub> emissions of the country since 1990s is shown in figure 2-2.

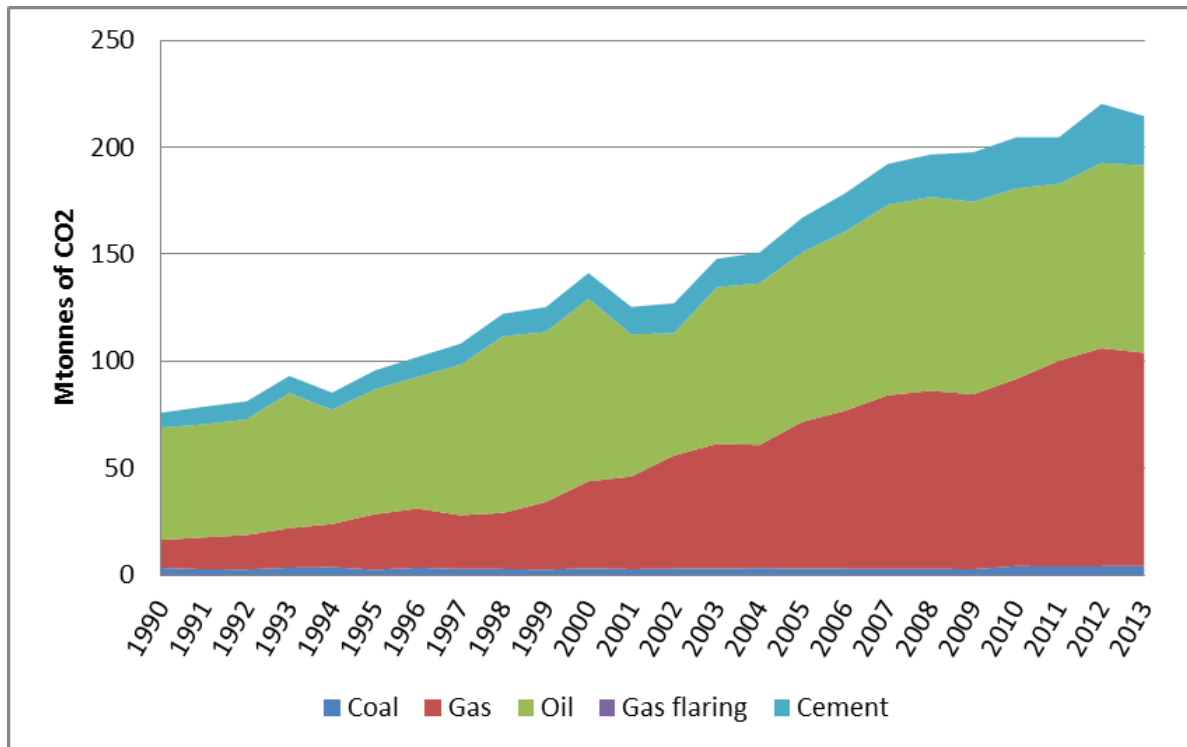


Figure 2-2: Energy related CO<sub>2</sub> emissions in Egypt from 1990 to 2013

(Source: Global Carbon Atlas 2014)

The Egyptian Environmental Affairs Agency defines the country's environmental policies. The entity established in 1982 and thereafter the Ministry of State for the Environmental Affairs was created. Environmental policy of the country (so-called National Environmental Action Plan) addresses environmental issues and strategies for encouraging effective use of energy in different oil sector activities, expansion of gas network and use of natural gas.

### Taxation Policy and Subsidies

Egyptian government provides subsidies for various types of fuel such as natural gas, kerosene, butane, diesel, gasoline and fuel oil. Gas prices are heavily subsidized for industrial usage and power generation to bring more incentives to both sectors for switching from oil and oil products to gas and thereby letting more oil for export.

Global fuel price rising in the international markets resulted in more restricted government budget. Moreover, cheap gas prices compare to global prices boosted domestic gas demand.



Following the national demand increase and no reaction concerning these subsidies, Egypt became a net importer of oil in 2010. This trend will most probably continue given the intensive depletion observed in the Egyptian oil fields in addition to the national demand increase.

Several announcements have been made by the government to decrease energy subsidies. For instance, in 2007, the Egyptian government announced its intention to phase out subsidies for natural gas for both energy intensive and non-intensive industries with different time horizons, respectively in 2009 and by the end of 2013. However, following economic crisis, the government fixed natural gas and electricity prices for all industries. Egypt spent around 20.3 billion dollars for energy subsidies in 2010, equivalent to almost 13% of the country's GDP. Anyway, subsidy reforms (particularly in residential and commercial sectors) seem to be very unlikely to be occurred, especially in power sector, under current peculiar socio-political situation of the country. We will discuss this issue in more details through the last chapter.

## **Oil and Gas Sectors Situation in Egypt**

Egypt has the largest downstream (refining) sector of Africa with 8 refineries with combined capacity of 700 kbbl/d. Egypt largest refinery is operated by El-Nasr Petroleum company at Suez with total capacity of 131 kbbl/d. Power sector consumed 14% of total demand of oil in 2010, almost 102 kboe/d. Transport sector is the largest consumer with more than 40% of the total demand.

Egypt commercial liquid reserves at the moment are estimated to be around 2.4 billion barrels (WoodMackenzie 2012). Most of them situated in the mature Gulf of Suez fields. Even though a huge depletion has been observed in these fields, Egypt has managed to keep the production almost constant. This is due to the successful reservoir management programmes and new developments in Western Desert. Key oil fields in the Western Desert are the Khalda and East Bahariya fields, both operated by Apache Company. Despite all these efforts, total Egyptian production has declined from 670 kbbl/d in 2000 to 417 kbbl/d in 2010 (IEA 2011). Increased investors' attention towards gas was also an important element behind this production decline. By 2030, oil production is expected to reach only 325 kbbl/d, half of the current level (WoodMackenzie 2012).

In 2010, more than 60% of the total gas production of the country went for power generation.

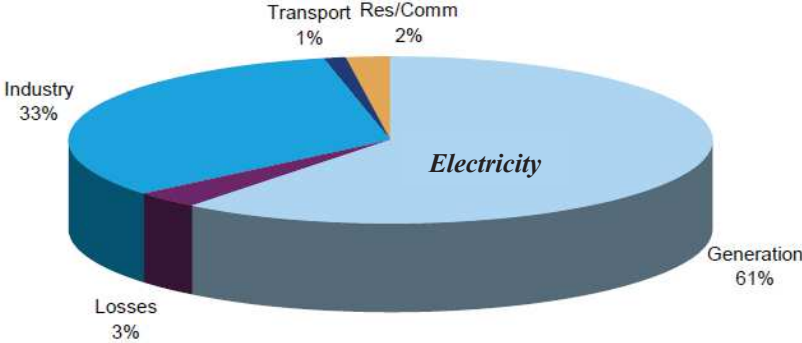


Figure 2-3: Demand for Gas in Egypt in 2010  
(Source: IEA)

Egypt has the 3<sup>rd</sup> largest gas reserves in the African continent after Nigeria and Algeria. Total reserves are estimated to be around 35.6 tcf. Majority of these reserves are located in Mediterranean deep water, Western Desert and North Alexandria. In terms of production, Egypt is the largest gas producer in Africa after Nigeria. Gas production started in Egypt in 1970s and boosted by strong national demand and long-term contacts for export. In 2010 Egypt produced 58.8 bcm (IEA 2011) of natural gas from its fields. Gas production is expected to be around 57 bcm by 2030 (WoodMackenzie 2012). This will make very difficult and challenging for Egypt to commit its LNG exports, satisfy its electricity growing demand and fully execute the previously mentioned Petrochemicals Master Plan. Oil and gas infrastructure and hydrocarbon fields locations in Egypt are shown in figure 2-4.

**New gas field discovery in Egypt**

Recently the Italian oil company ENI announced the discovery of a giant gas field in Egypt. Named “ZOHR” is said to be the largest in the Mediterranean region with the estimated capacity of 850 billion cubic meter, equivalent to around 5.5 billion barrel of oil equivalent.

The production will probably start in 2017 according to ENI which holds 100% of the exploitation licence.

Both Italian and Egyptian officials reckoned that this discovery can dramatically change the energy landscape of the country and transform the national energy scenarios (Le Monde 2015). But we should not forget the fact that if we consider always only the international opportunity price of fuel (in this case natural gas), this discovery would not impact the result of our model based on the current situation of hydrocarbon resources without taking into account this giant discovery.



Figure 2-4: Oil & Gas infrastructure in Egypt in 2010

(Source: WoodMackenzie)

## **Egypt's power sector: past and present**

Efforts to reform the Egyptian electricity supply industry originated as early as 1964, when the national utility was unbundled and eight distribution companies were created. This arrangement remained until 1992, when the distribution companies were transferred from the Egyptian Electricity Authority (EEA), under the auspices of the Ministry of Electricity and Energy, to the Ministry of Public Enterprises, with the aim of further corporatizing the entities. By 1998, with little progress achieved, a decision was taken by the Ministry of Electricity and Energy to transfer the entities back to the EEA, then re-bundle the distribution and generating entities into seven subsidiary and state monopolies (an activity charged by some observers as counter to reform).

With the backdrop of the re-bundling of state utilities, privatization efforts were slowly taking hold. In 1996, Law 100 was issued which specified: “local and foreign investors may be granted public utility concessions letting them to build, operate and maintain electric power plants”. In 1997, a new investment decree was introduced, which spelled out a number of investor incentives including government warranties to secure projects. At the time, the sector was averaging peak demand growth of 7.6% per year and progressively controlled by natural gas as the primary fuel for electricity production. In 1980, the share of natural gas amounted to only 20% of total power generation, hydro accounting for 51% and oil making up the balance. Ten years after, the share of natural gas amounted to more than 40% and two decades later up to even more than 80% of the total power generation mix. Consequently, Independent Power Producer (IPP) bids for a series of gas power plants were tendered and successively awarded in 1998 and 1999. In parallel, shares of seven state-owned monopolies were prepared to be offered on the stock exchange in Egypt, but little interest by investors, this plan has never been occurred. Another major phase of reform was the reorganization of the EEA into the Egyptian Electricity Holding Company (EEHC) in year 2000, through Law 164. It also involved the unbundling of the seven vertically integrated subsidiaries and the subsequent separation of generation, transmission and distribution activities. Each generation and distribution subsidiary was established as a separate corporate entity with its own board and external reporting. An internal pool was also created for bidding-in electricity, even though ex-post price adjustments in the pool extensively weakened its potentially positive incentive effects.

The corporatization of EEHC was planned as a step to prepare shares for privatization, nevertheless, as of 2015, this process has not yet initiated. Government still holds 90% of generation capacity and maintain a monopoly over transmission and distribution through EEHC. And corporate governance regimes have not been strong and are characterized by substantial involvement of the Ministry of Electricity and Energy who chairs the EEHC, in the operating decisions of the agency's subsidiaries.

It is very important to note that these reforms happened in the absence of an independent regulatory entity. In spite of the issuance of a decree to institute a regulator as early as 1997, no progress was made. Finally in 2002, the Egyptian Electric Utility and Consumer Protection Regulatory Agency (ERA) was established. Its main objective is to create conditions in which bilateral contacts between producer and consumer follow the norm and third party access to the transmission system is properly provided.

Yet, there is a competition in generation part of the sector in Egypt in spite of the nonexistence of a proper privatization. Currently no explicit price control applies in the generation side of the business, however the regulators monitor the production adequacy and implement incentives to promote new investments.

Under the current market model of Egypt, only new capacity expansions are under competition and the plants' operations are mainly financed through power purchase agreements. Generators are paid for both "energy" and "availability" and therefore compensated for both fixed (e.g. investment) and variable costs (fuel and O&M).

### **Current Power Sector Overview**

Following above-mentioned restructuring and unbundling reforms in 2001, the existing vertically integrated monopolistic system was unbundled into six generation, one transmission and nine distribution companies. Under the supervision of the Ministry of Electricity & Energy, the Egyptian Electricity Holding Company still owns 90% of generation and distribution sectors and 100% of the transmission company. The Egyptian Electricity Holding Company (EEHC) is the only entity empowered to approve and construct any generation capacity or to buy power from international private developers of electricity. Even though the 2001 unbundling reforms aimed to eventually privatize the sector, but Electricity Holding

Company remained 100% public and it is very unlikely to see any privatization process in the near future. Organization of power sector in Egypt is shown in figure 2-5.

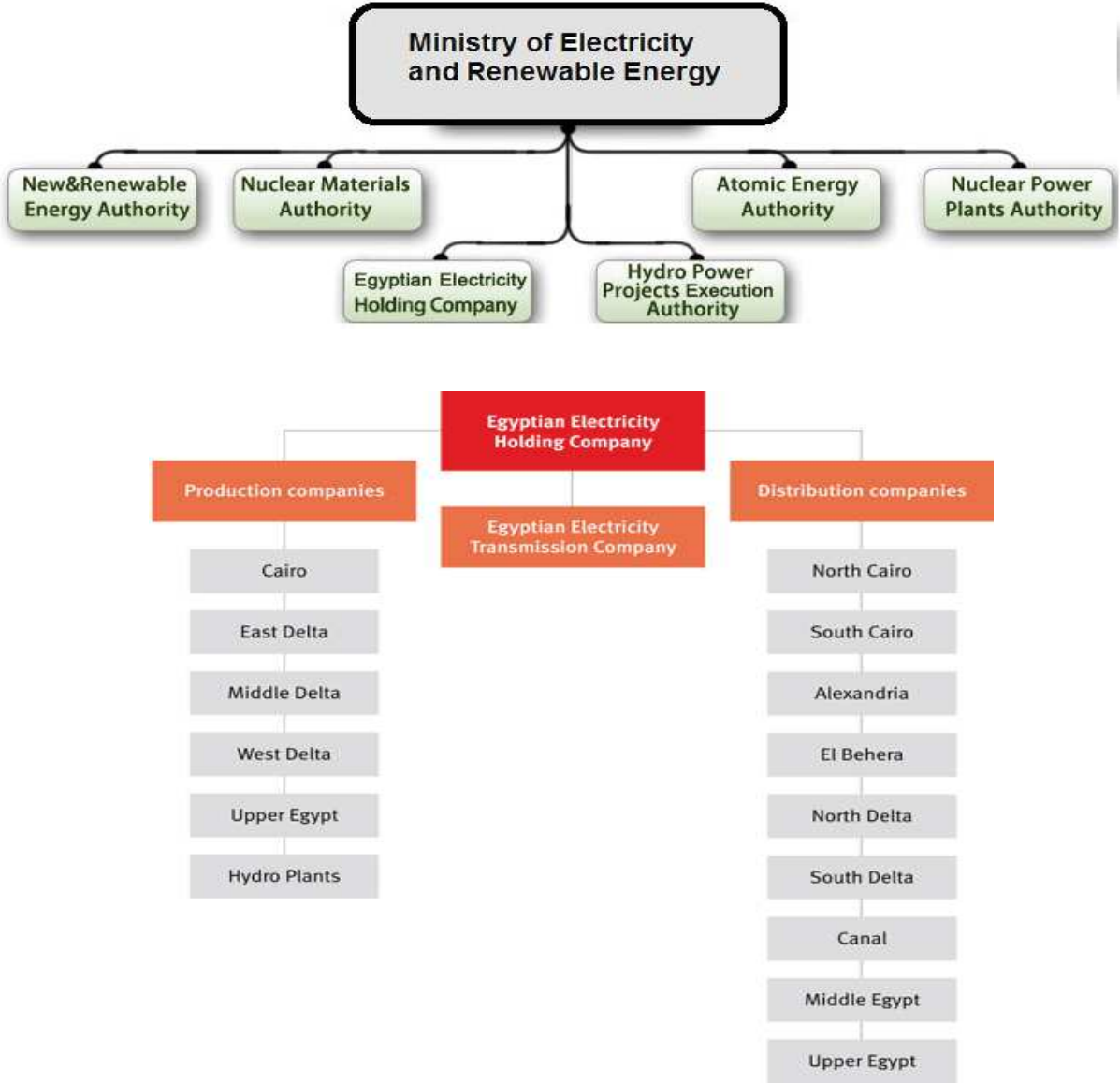


Figure 2-5: power sector organization in Egypt  
(Source: NREA, EEHC)

Egyptian Electricity Holding Company (EEHC) consists of totally sixteen electricity companies separated according to the region in which they operate and also the fuel type they use. Cairo, East Delta, Middle Delta, West Delta and Upper Egypt are the thermal power companies while Hydro Plans Company is in charge of all hydro generation across the country. Several privately owned power units have also financed and built under BOOT (Build, Own, Operate and Transfer) financing scheme put in place in late 2002 by the Egyptian government. Port Said East Power Company, the Sidi Krir Generation Company and the Suez Gulf Company are examples of these private operators. There are currently three International Private Producers operating in Egypt. The first international operator was US-based InterGen, a joint venture of Bechtel Enterprises and Shell Generating Limited, along with some local partners to operate Sidi Krir BOOT project.

At the moment power market in Egypt is organized in the “Single Buyer”<sup>12</sup> structure. Egyptian Electricity Transmission Corporation sells power from the generation entities (including private independents) to the 9 regional distribution companies. Approximately 10% of the Egypt’s distribution grid is owned by 6 small private companies who manage the sale of mid and low voltage power to final consumers. These companies are as following: Global Energy Company, the Alexandria Carbon Black Company, the Om El Goreifat Company, the National Electricity Technology Company and finally the Mirage Company. For the purpose of controlling and regulating all the issues related to generation, transmission, distribution and consumption, the Egyptian Electric Utility Organization & Consumer Protection agency was created in 1997 by the government. Many other specialized regulatory authorities have also been established to regulate the various areas of the power sector, such as Nuclear Power Plants Authority, New & Renewable Energy Authority, Hydro Power Projects Execution Authority and etc.

## **Electricity Supply and Power Plants**

Egypt has increased its generation capacity from 15.5 GW in 2000 to almost 27 GW in 2010. Power output has also been doubled from 78.1 TWh in 2000 up to 148 TWh by 2010 (IEA 2012). Currently the network loss in Egypt is around 12% and for the time being there is no serious plan for reinvestment in the Egyptian transmission system. EEHC had to deal with

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<sup>12</sup> For more information regarding this market model please refer to appendix 2-A.



some outages in 2010 during peak hours because of the growing usage of air-conditioners during hot days. Still the problem is not really solved and moreover there was a growth of almost 7% in peak load between 2009 and 2014.

Egyptian government announced ambitious goals for increasing capacities to satisfy the growing domestic demand. EEHC is currently applying the 6<sup>th</sup> Five Year Plan targets capacity additions of 7 GW over the 2007-2012 periods (EEHC 2010/2011 annual report). The plan includes 3 GW of Combined Cycle and 4 GW of Steam Turbine capacities. Recently, EEHC has also proposed the 7<sup>th</sup> Five Year Plan for 2012-2017 periods, including an additional 5.25 MW of Combined Cycle plus 7.15 MW of Steam Turbines.

Concerning renewables, in 2007, the Renewable Energy Expansion Plan adopted for renewable penetration of 20% in to the network by 2020, where hydro power represents 5.8%, wind 12% and 2.2% from other renewable energy sources, especially solar (EEHC 2010/2011 annual report). In September 2014, the Egyptian Ministry of Electricity and Energy has introduced specific feed-in tariffs for electricity generated by distributed solar and wind sources. This support scheme is at the very beginning phase and will probably go through more adjustments in the near future.

Combined cycle and steam units (both using natural gas as fuel) accounted for 62% of the total capacity in 2010. These technologies have been considerably promoted by the Egyptian government since 2000 as gas production increased and subsidies over natural gas encouraged the investment in this technology. In 2011, Al Damietta and Al Shabab power plants with total capacity of 1.7 GW were added to the network.

Egypt started producing hydro power in 1960's after the construction of the Aswan High Dam station. Since then, no new major project has been realized. In 2010, total capacity of hydro was 2.8 GW accounting for 9.5% of total generation (IEA 2012). Almost all of the hydroelectricity generated in Egypt comes out of the Nile river. Its flow is shared between Egypt and neighbouring countries: Ethiopia and Sudan. In the future Egypt should absolutely reach a sustainable solution with its neighbours regarding the Nile's flow sharing. (More detailed information regarding the water flow sharing challenges in Nile is given in the Appendix 2-E of this chapter)

Oil-firing power plants account for 18% of power generation of the country it has not historically been encouraged by the government because of its expensive price leading to very

high subsidies for the government. Oil has been mainly used in the peak summer months for meeting air-conditioning demand. Share of each fuel type in the total power generation of the country since 1972 up to now is shown in figure 2-6.

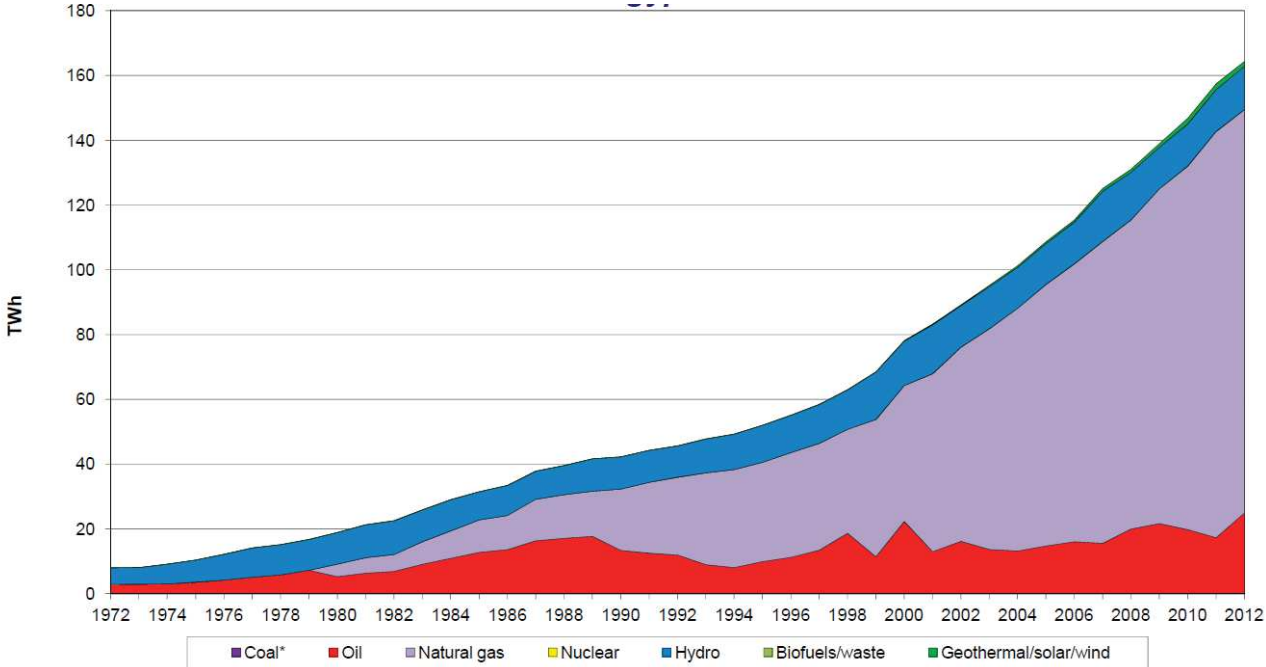


Figure 2-6: Electricity generation by fuel type in Egypt in 2010  
(Source: IEA 2014)

Nuclear power has also been proposed several times by the Egyptian government. Plan to develop this technology were put in place in the 1980’s. 1000 MW nuclear capacity were proposed at El Dabaa on the Mediterranean coasts. Project was halted due to the huge costs and safety reasons following the Chernobyl accident. In 2006, following an increase in international oil and gas prices and rising domestic demand of power, the nuclear program revised by the government. Finally, in 2010 Egypt lunched a tender for 1.2 GW El Dabaa Plant with forecasted cost of 1.5 billion dollars and commissioning date of 2019 (Selim 2009).

There are also some power stations in Egypt which are not connected to the unified power system and mainly installed at remote areas so as to provide electric power to touristic projects and other purposes. These are 30 power plants with total installed capacity of 230 MW installed in isolated zones and connected to the distribution networks of those zones in addition to one 5 MW wind farm in Hurghada.

Figure 2-7 and Table 2-1 demonstrates respectively the entire electricity infrastructure and power plant stations of the Egypt.



Figure 2-7: Electricity generation and transmission infrastructure in Egypt in 2010

(Source: WoodMackenzie & GENI)

Comp.	Station		No. of Units	Installed Capacity (MW)	Actual Capacity (MW)	Fuel	Commissioning Date
Cairo	Shoubra El-Kheima	(St)	4 x 315	1260	1260	N.G-H.F.O	84-85-1988
	Shoubra El-Kheima	(G)	1 x 35	35	35	N.G-L.F.O	1986
	Cairo West Ext	(St)	2 x 330 + 2 x 350	1360	1360	N.G-H.F.O	1995-2011
	Cairo South I	(CC)	3 x 110 + 2 x 60	450	400	N.G-H.F.O	1965-1989
	Cairo South II	(CC)	1 x 110 + 1 x 55	165	150	N.G	1994
	Cairo North	(CC)	4x 250 +2 x 250	1500	1500	N.G-L.F.O	2004-2006-2008
	El-Tebeen	(St)	2 x 350	700	700	N.G-H.F.O	2010
	Wadi Hof	(G)	3 x 33.3	100	75	N.G-L.F.O	1985
	6 October	(G)	4 x 150	600	600	N.G-L.F.O	2012
	North Giza <sup>(2)</sup>	(CC)	3x 250	750	750	N.G-L.F.O	2014
East Delta	Damietta	(CC)	6 x 132 + 3 x 136	1200	1164	N.G-L.F.O	1989-1993
	Ataka	(St)	2 x 150 + 2 x 300	900	900	N.G-H.F.O	1985-86-1987
	Abu Sultan	(St)	4 x 150	600	600	N.G-H.F.O	1983-84-1986
	Shabab	(G)	3 x 23.5	100.5	91.5	N.G-L.F.O	1982
	New Gas Shabab	(G)	8 x 125	1000	1000	N.G-L.F.O	2011
	New Gas Damietta	(G)	4 x 125	500	500	N.G-L.F.O	2011
	Damietta West	(G)	4 x 125	500	500	N.G-L.F.O	2012
	Port Said	(G)	2 x 23.96	48	44	N.G-L.F.O	1977
	Arish	(St)	2 x 33	66	66	N.G-H.F.O	1995-1996
	Oyoun Mousa	(St)	2 x 320	640	640	N.G-H.F.O	2001
	Sharm El-Sheikh <sup>(3)</sup>	(G)	x 23.7 + 4 x 24.27 + 1 4 x 5.8 + 2 x 5	144	131	L.F.O	1975-1979-1997
	Hurghada	(G)	6 x 24.2	143	131	L.F.O	1977-1979
	Zafarana(Wind) <sup>(4)</sup>	(W)	x 0.6 + 117 x 0.66 + 105 478 x 0.85	547	70	Wind	2007-2008-2009-2010
Suez Gulf (BOOT)	(St)	2 x 341.25	682.5	682.5	N.G-H.F.O	2002	
PortSaid East(BOOT)	(St)	2 x 341.25	682.5	682.5	N.G-H.F.O	2003	
Middle Delta	Talkha	(CC)	8 x 24.72 + 2 x 45.94	290	236	N.G-L.F.O	1979-80-1989
	Talkha 210	(St)	2 x 210	420	420	N.G-H.F.O	1993-1995
	Talkha 750	(CC)	2 x 250 + 1 x 250	750	750	N.G-L.F.O	2006-2010
	Nubaria 1,2	(CC)	4 x 250 + 2 x 250	1500	1500	N.G-L.F.O	2005-2006
	Nubaria 3	(CC)	2 x 250 + 1 x 250	750	750	N.G-L.F.O	2009-2010
	Mahmoudia	(CC)	8 x 25 + 2 x 58.67	317	268	N.G-L.F.O	1983-1995
	El-Atf	(CC)	2 x 250 + 1 x 250	750	750	N.G-L.F.O	2009- 2010
	Banha <sup>(5)</sup>	(CC)	2 x 250	500	500	N.G-L.F.O	2014
	West Delta	Kafr El-Dawar	(St)	4 x 110	440	440	N.G-H.F.O
Damanhour Ext		(St)	1 x 300	300	300	N.G-H.F.O	1991
Damanhour (Old)		(St)	3 x 65	195	180	N.G-H.F.O	1968-1969
Damanhour		(CC)	4 x 25 + 1 x 58	158	154	N.G-L.F.O	1985-1995
El-Seiuf		(G)	6 x 33.3	200	141	N.G-L.F.O	1981-1982-1983-1984
Karmouz		(G)	1 x 11.37 + 1 x 11.68	23.05	18	L.F.O	1980
Abu Kir		(St)	4 x 150 + 1 x 311	911	900	N.G-H.F.O	1983-1984-1991
Abu Kir		(G)	1 x 24.27	24	23	N.G-L.F.O	1983
Abu Kir New		(St)	2 x 650	1300	1300	N.G-H.F.O	2012-2013
Sidi Krir 1,2		(St)	2 x 320	640	640	N.G-H.F.O	1999-2000
Sidi Krir		(CC)	2 x 250 + 1 x 250	750	750	N.G-L.F.O	2010
Matrouh		(St)	2 x 30	60	60	N.G-H.F.O	1990
Sidi Krir 3,4 (BOOT)		(St)	2 x 341.25	682.5	682.5	N.G-H.F.O	2001
Upper Egypt	Walidia	(St)	2 x 300	600	600	H.F.O	1992-1997
	Kuriemat 1	(St)	2 x 627	1254	1254	N.G-H.F.O	1997-1998
	Kuriemat 2	(CC)	2x250+1x250	750	750	N.G-L.F.O	2007-2009
	Kuriemat 3	(CC)	2x250+1x250	750	750	N.G-L.F.O	2009-2011
	Assiut	(St)	3 x 30	90	60	H.F.O	1966-1967
	Kuriemat Solar/ Thermal	(S/G)	1 x 70 + 1 x 50 + 1 x 20	140	140	Solar/ N.G	2011
Hydro Plants	High Dam		12 x 175	2100	2100	Hydro	1967
	Aswan Dam I		7 x 40	280	280	Hydro	1960
	Aswan Dam II		4 x 67.5	270	270	Hydro	1985-1986
	Esna		6 x 14.28	86	86	Hydro	1993
	Naga Hamadi		4 x 16	64	64	Hydro	2008

Table 2-1: Egyptian power stations statistics

(Source: EEHC 2014)

## **Methodology**

For analysing how to rank increasing generation capacity, in this chapter we apply a dynamic linear programming model for the power planning of Egypt for the next few decades, assuming that the corresponding infrastructure is there. In this way, we deliver implications on the optimal investment trend in the power generation capacity. In this context, being optimal would imply the least cost of power generation while catering to meet the growing electricity demand. This contains also the issues of carbon emissions. Dynamic linear programming framework in electricity generation was first used by Turvey & Anderson (1977). In such models, taking a long term horizon, the planner's aim is to put in place plant capacities and outputs in order to minimize the present value of total costs.

Alike the first chapter, a linear programming optimization framework was used to assess the costs and savings of expanding the role of non-fossil fuel based power sources in electricity supply. A cost-minimization approach that systematically evaluates potential power supply to satisfy the demand at least cost. In the other words, we analyse what the incremental cost would be if each sources of power generation were to integrate the electricity supply of the country. And unlike the static model of Saudi Arabia, we introduced a dynamic process of technology choosing for investment trends incorporated into the optimization model.

Electricity generation should be provided by a large set of power plants which are characterized by different technologies associated to a very large spectrum of fixed and running costs. Consequently, this leads to an optimal usage and investments so as to satisfy the current and future demand. Optimizing the overall electricity cost of production by the deferent types of plants enables us to rank the existing production means. Indeed, when electricity demand increases and the available power (in the lowest cost category of generation means) is not enough, we must switch to the generation-mean whose cost category is just one step above the previous one. Brief, in the short-term approach, we rank the use of power plants according to their growing running cost and in longer terms, a dynamic process of investment in power units is allowed.

The main contribution of this study is to analyse the optimality of the Egyptian power generation park via LP models (based on the above-mentioned structure) and to reveal the most optimal decisions for the next 20 years of the national electric system under different least-cost proposed investment scenarios provided by the dynamic LP model. Afterwards, the sensitivity analysis is accomplished to measure the competitiveness of non-fossil power

resources (renewables and nuclear) with fuel-based ones under various discount rate and carbon price scenarios.

One of the main approaches of power generation modelling deals with minimizing the electricity generation cost so as ours. Examples of such models include Kreuzberg (1999), Musgen & Kreuzberg (2001), Kramer (2002), Kurihara et al (2002) and ILEX (2003). Many other examples have also been developed by consultants and utilities themselves and are not therefore published. The basic idea of these models is to explain electricity prices from the marginal generation cost. In this case, assumption over the future electricity prices does not have to be made. Focusing on minimum generation cost implies minimizing the cost to be transferred to the final consumers, irrespective of the electricity price. The main advantage of this method is to study the agent behaviour faced with a mix of deferent types of constraints such as economic, technical and environmental ones. Our approach is similar in the way that we develop a linear (dynamic) model where the total costs are minimized, whatever the electricity prices would be in the system.

## **Modelling Framework**

Optimizing the overall production cost of electricity via various types of power plants enables to prioritize and rank the different means of production. Indeed, when electricity demand increases and the power available in the category of lowest cost is not enough, then it should implement the generation mean whose cost category is immediately above. This leads to a prioritizing of different equipment based on their operating costs which allows defining a dispatching of different equipment on the annual load curve. Generation mix management, made by the cost minimization objective, corresponds to an economic optimum: at each time step, the marginal cost (the cost to satisfy a request from a marginal additional MWh) is equal to the proportional cost of producing the marginal equipment. All equipment with lower cost of production will be used and in theory, no more expensive equipment will produce.

In medium and long-term, particularly with taking into account the investment costs associated with capacity constraints to be determined, the use of optimization techniques can be very useful. The proposed model in this study is solved using dynamic linear programming so as to consider those investment trends to satisfy the growing demand of the country. Optimal management assumes that production units reach saturation capacity when, for the

remaining power-call duration to cover, they are not profitable anymore. This management justifies the use of above-mentioned optimization techniques to solve the problem we have just described.

Alike previous chapter we model the power generation park structure of Egypt in GAMS 24.0.2 (General Algebraic Modelling System) platform within CPLEX as a solver. This cost minimization model contains the objective cost function that must be minimized and the demand constrains that have to be satisfied. For static short-term optimization, the production capacities must be respected and in the case of long-term optimization, dynamic investments are allowed.

The constraints of the model are the demand equations, the capacity constraints and the investment equations. In the demand equations for each season, the sum of the power generated by the power plants is greater than the demand. On the supply side, the power loaded from each unit is lower than the power capacities times the seasonal availability coefficients. Finally, the installed capacities are equal to the sum of the existing units and investments.

The model is developed based on a long time period. This period is split in several sub-periods associated to the time index  $t$  with  $n(t)$  years. In each sub-period, we consider a representative year denoted by  $a(t)$ . Thus there are  $b(t)$  years before period  $t$  defined as follows:

$$b(t) = \sum_k^{t-1} n(k)$$

The model basic structure is as following (schematic structure of the model is shown in Appendix 2-D):

$$\text{Min} \sum_t \left[ \sum_i \sum_s \sum_m (\gamma_t \times E_{ia(t)} \times H_s \times R_m) P_{isma(t)} + \sum_i (\varphi_t \times I_{ia(t)}) C_{i(t)} \right]$$

With,

$P_{isma(t)}$ : is the Power loaded (called) on the grid by each equipment of type  $i$ , for the season  $s$  in the representative year  $a(t)$  with demand randomness factor of  $m$  (MW)

$H_s$ : Length of the season  $s$  (hours)

$E_{ia(t)}$ : Variable cost of production of each equipment  $i$  at the representative year  $a(t)$  (\$/MWh)

$t$  : the time period (step)

$a(t)$  : representative year of the period  $t$

$R_m$  : probability of having randomness factor of  $m$

$I_{ia(t)}$ : investment in the unit  $i$  at the representative year  $a(t)$  (\$/kW)

$C_{i(t)}$ : capacity to build for unit  $i$  at the period  $t$  (MW)

$\gamma_t$  is the discount factor applied to the annual costs of each period. We assume that the costs are the same for all the year of a given planning period, thus it is defined as :

$$\gamma_t = \frac{1}{(1+r)^{b(t)}} \sum_{k=1}^{n(t)} \frac{1}{(1+r)^k}$$

And  $\phi_t$  is the discount factor applied to investments :

$$\phi_t = \frac{1}{(1+r)^{b(t)}}$$

Where  $r$  is the discount rate.

Hence we minimize the total discounted cost of different installed units according to the demand and available capacity. We apply different discount factors for the variable cost and investment cost. As a matter of fact, the variable cost is different every year and the discount factor varies accordingly. Instead, the discount factor corresponding to future investment is less complex since, by convention, we invest in year 0 (overnight costs), but repayment of annuities is done throughout the life time of the power plant.

For each period, supply (capacity) and demand sides' constraints are as following:

Capacity constraint:

$$\frac{1}{\tau_{is}} P_{isma(t)} \leq \sum_i \alpha_{i\theta} C_{ia(\theta)}$$

With,



$\alpha_{i0t}$  : coefficient of availability of the equipment  $C_{ia(t)}$  activated in year  $t$ . It measures the capacity reductions that occur after the construction of a plant.

$\tau_{is}$ : coefficient of availability in each season for each equipment  $i$

And the evolution of production capacity (new additional investment) during the modelled time horizon is satisfied by the following dynamic power-unit fleet relation:

$$C_{i,t} = C_{i,t-1} + U_{i,t} \quad \text{with } U_{i,t} \geq 0$$

In which,  $C_{i,t}$  and  $C_{i,t-1}$  represent the capacity of equipment  $i$  during two consecutive years, and  $U_{i,t}$  is equal to the capacity evolution of unit  $i$  in year  $t$ .

Demand constraint:

All the equipment must provide the seasonal power required for the satisfaction of the consumers demand and this must be done for each random event  $m$ .

$$\sum_i P_{isma(t)} \geq D_{sma(t)}$$

$D_s(t)$ : called power on the grid for the season  $s$  (MW)

More details concerning model's equation in GAMS are available in the Appendix 2-B of this chapter.

### Demand Structure and Modelling

Figure 2-8 indicates daily electricity demand curve (load-curve) of Egypt.

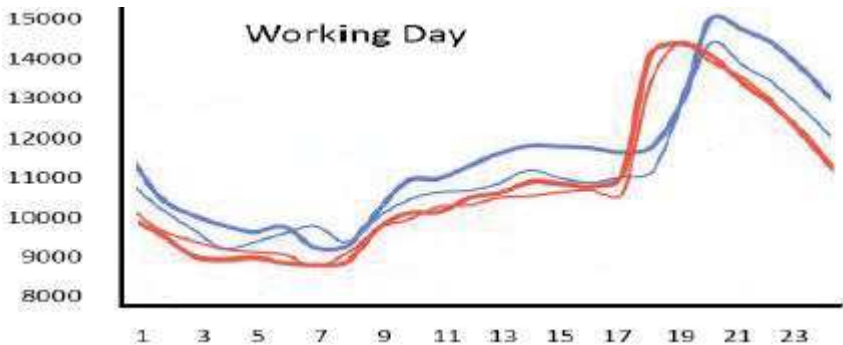


Figure 2-8: Typical daily load-curve (MW) in Egypt (red goes for winter and blue for summer)

(Source: Beshara 2008)

In this study we considered three demand fractions:  $F_1$ ,  $F_2$  &  $F_3$ .  $F_1$  represents the base-load and  $F_2$  &  $F_3$  represent respectively the semi-base and peak daily demands. Thereafter we spread this 3-fractionned structure of the daily demand through two different seasons:  $S_1$  &  $S_2$ .  $S_1$  represents summer season in which we generally observe the peak demand periods (caused by the air-conditioning effect) and  $S_2$  goes for winter season. In figure 2-9 we show these demand compositions for our fractional hours and seasons hypothesis.

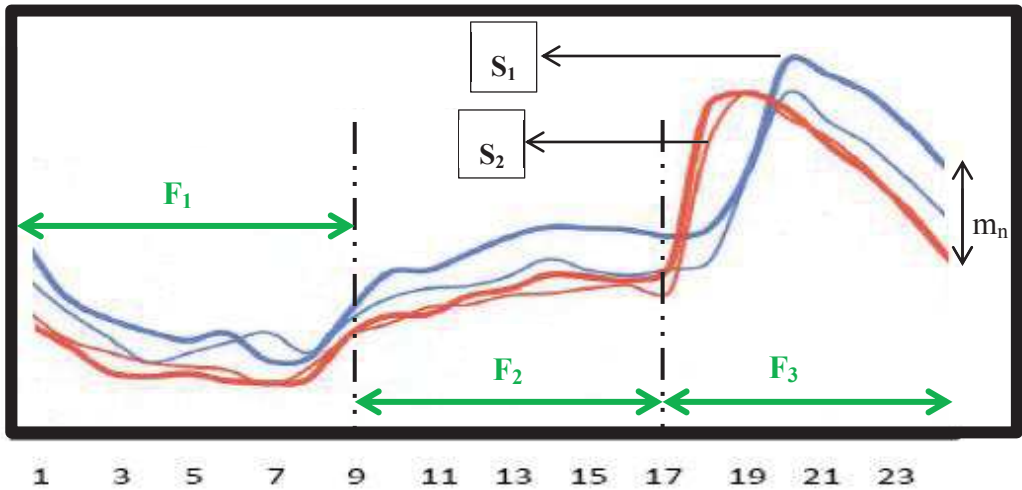


Figure 2-9: Demand’s structure in the model

Demand randomness factors and their associated probabilities ( $m_n$  parameters in the optimization model) introduced in the model, assume 10% variability of the registered demand in both negative and positive directions.

Demand increase forecasts for 2020 and 2030 are respectively equal to almost 35 and 17 per cents (WoodMackenzie 2012). Demand values and associated share of each fuel used in the model for the reference year 2010 and forecasted ones, 2020 and 2030 are summarized in table 2-2.

<b>Total electricity demand in Egypt (TWh/y)</b>				
<i>2000</i>	<i>2005</i>	<i>2010</i>	<i>2020</i>	<i>2030</i>
<b>78</b>	109	148	200	236

Table 2-2: Egyptian power demand  
(Source: WoodMackenzie, IEA & EEHC)

As the share of hydroelectricity remains constant, equal to that of 2010, during modelled time horizon (owing to the already saturated potential of hydroelectricity in Egypt) we subtracted the hydro share directly from the demanded electricity. In the case of other renewable resources, notably wind turbines, certain amount of renewable production (according to the Egyptian government target and proposals for renewable share) has been imposed on the loaded power as must-run production units with intermittency effects of course.

**Renewables Intermittency and Necessity of Back-Up Plants**

So as to cover the risk related to the intermittent production of solar and wind power plants, we have introduced in the model a necessary investment in the fossil-fuel power plants that play a back-up role in case of insufficient capacity factor that could happen during peak consumption, especially in summer. This back-up capacity is based on the difference between the average capacity factor of the intermittent means and their capacity factor during peak demand of electricity. In most of the regions around the world, lowest values of capacity

factor for the intermittent technologies are observed during peak demand periods. This is also the case of Egypt with hot and not necessarily very windy summers.

In our model the absence of production from intermittent means is compensated by the least expensive (in terms of total cost) thermal power units which have around 100% of availability (capacity factor equals to 1) except for the ex-ante planned maintenance. So the total cost of power generation, for the renewable units, includes these back-up costs.

Wind speed can widely fluctuate in a rather short-time period. These fluctuations cause the need to rapidly compensate for large amounts of increased or decreased production with other power plants in the system. The most reliable way to answer these variations is to use pumped storage and hydro storage facilities which have very quick ramp (start-up) possibilities with relatively large power volume capacities. Unfortunately there is not enough potential for these technologies in Egypt due to its climatic situation. Open cycle gas turbines can also quickly start and make up for the losses in production as it is not necessary to pre-heat water in these plants, contrary to both steam plants and combined cycles. CCGTs take longer to ramp up their output, whilst steam turbines are even slower. Even though the existing and already operational flexible power plants could be used to provide the needed flexible back up for renewables, but it works only in very short term. In longer terms, with the aging of existing power plants and integration of more renewables in the system (up to 20%), construction of conventional back-up power plants would be vital for the stability of the Egyptian power system.

It is also worth to mention that nuclear power can also play a flexible back-up role in power systems. Contrary to what is commonly believed, nuclear power plants have (on average) very responsive load gradients (about 5% of load per minute) even though their start-up time is very long from both warm and cold conditions. For the time being this flexibility potential exist only in very experienced countries in realm of nuclear industry such as France and Germany for example. Therefore, flexibility analysis of nuclear plants is out of the scope of this study due to the fact that Egypt will be a newcomer in the nuclear sector (if the country adopt for the installation of before-mentioned power plants in the time horizon of this study). Under the explained assumption of 20% renewable integration (for both years 2020 and 2030), at least 4GW and 6GW of flexible back-up facilities would be needed respectively for the years 2020 and 2030. These added capacities do not include the replacement of retired old-age existing power units during the studied period. The necessary replacement capacity is

calculated by the model without any flexibility concern for the future power plants. Therefore less flexible plants (such as nuclear in our case) have also been considered. This is not the case of our additional cost calculation for renewables accompanied with back-up units and their associated costs of-course.

## **Fuel Costs**

For the fuel costs we follow the strategy that we developed in the modelling framework of Saudi Arabia in the first chapter. Hence, they are integrated in the models in dollar per MWh based on the data provided from BP Statistics, IEA, EIA, IMF and World Bank. For example in the case of gas prices we considered the minimum average price of large gas producing countries around 7 USD/MMBtu, where domestic prices of natural gas can decouple from international market prices without implementing any subsidy. And for oil, Dubai dated average price over the last 4 years has been considered (80 USD/bbl) even if sometimes we use oil products in power generation which are more or less expensive than the crude itself.

In the case of uranium, in the model we used the nuclear fuel price of 7 USD/MWh (proposed by IEA and NEA) plus 2.5 USD/MWh more for transport, storage and eventually repossessing and final disposal according to the IAEA estimations. According to the International Atomic Energy Agency red-book, only 13 uranium enrichment facilities are currently in operation in the world at commercial scale and 40 places for fuel fabrication. Therefore, our constant fuel price assumption is more robust in case of Uranium compare to fossil fuels.

Even though in this study we assume stable fuel prices for the matter of simplicity; this should not be considered or interpreted as any sort of prediction of stable energy markets.

### Simulation Results and Economic Analysis

Model has been run for thirty consecutive years (details of the model’s output could be found in Appendix 2-C). Investments are allowed in the model during all of the periods and time steps so as to satisfy the imposed demand increase. Seasonal and daily demands have been associated with the randomness factors already described in the modelling frame-work section of this paper. Sensibility analysis and uncertainties were integrated into the model through various discount factors. Figure 2-10 shows the model outputs for different discount factors considered in the model. The major impact of discount rates is on the value of levelized generation cost per MWh which itself includes investment, O&M and fuel costs. In this scenario carbon cost is equal to zero and therefore direct emissions resulting from fossil fuel power plants usage have been neglected.

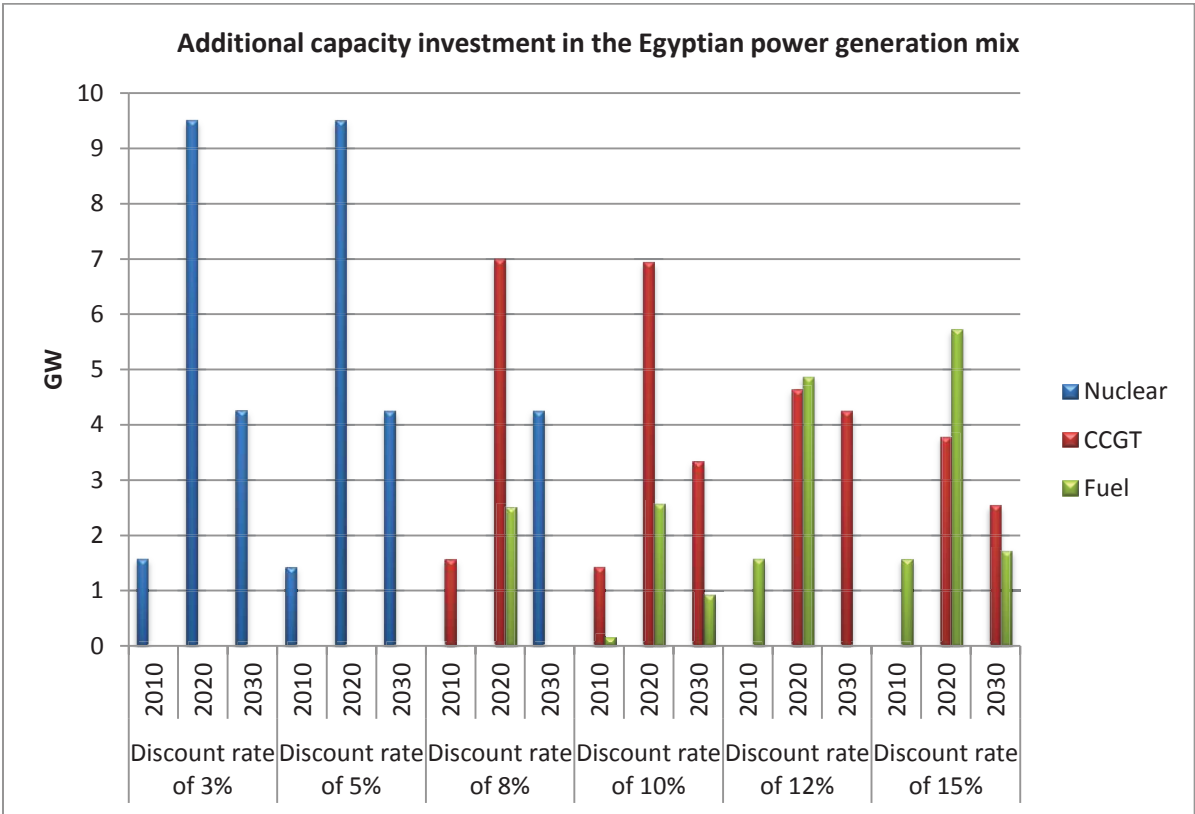


Figure 2-10

For discount rates below 5%, total demand increase is satisfied with nuclear energy which is considered as the most viable and economic way of generating electricity. Almost 10% of the total investment takes place in the base year 2010. This is almost tripled in the final year 2030. Nonetheless most of the investment occurs in the middle periods between 2010 and 2030. For example in 2020 around 60% of the total investment decision has been realized and the model recommends 9.5 GW of investment in total installed capacity of the country.

For discount rates above 5% other fossil resources, particularly CCGT power plants, become more economic. For instance at 8% discount rate, the model suggests about 1.8 GW of investment in total capacity with CCGT power plants (consuming only natural gas as a fuel) from the beginning of our base (reference) year of 2010. In 2020 (middle period) model suggests not only CCGT technologies but also fuel power plants. Total amount of suggested investment in fuel power plants reaches almost 35% of total additional capacity in 2020. The remaining capacity investment is still in CCGT technologies. The model considered 100% fossil-based generation park (as the most optimal one) up to at least 2025. From then on nuclear technology becomes again the most optimal solution to answer the further increase of electricity demand. The fact that technologies within huge initial investment costs (overnight costs) and long construction times become more economic only at the end of the period could be explained by their notable sensibility to large discount rates. Moreover, as we have assumed in our model that the last periods' demand will remain constant for a very long period of time (an assumption used for increasing the reliability and rationality of the model for investment decision making), nuclear power becomes less risky and optimal solution for long-term demand satisfaction. Economic viability of this long-term decision-making strategy turns out to be less rational for discount factors higher than 8% and even wholly disappears for discount factors rates above 10%.

By looking at the results in figure 2-10 we can observe that for the discount rate values above 10%, investments in fuel power plants turns out to be optimal from the beginning and becomes even the only optimal choice after 12%. Short construction time (compare to the other technologies) and rapid return on investment are the main reasons behind this expensive 100% fuel plants investment. Prompt satisfaction of accelerating electricity demand with least

costs, is also another reason. However, by moving further in time and giving more time to the investor(s), more capital intensive technologies such as CCGT come into action once more. It should not be forgotten that the above conclusions obtained under the zero carbon emission price assumption and they can be totally altered by setting a certain amount of CO<sub>2</sub> price in the model. Henceforth, we have introduced CO<sub>2</sub> costs in the model. Carbon emissions' amounts were integrated as physical property of each fossil fuel type by taking into account the thermal efficiency of each fossil power plant. Initially we designate the CO<sub>2</sub> price of 10€ per tonne and then we run the model again. Figure 2-11 demonstrates the investment results under this assumption for the same discount rate intervals.

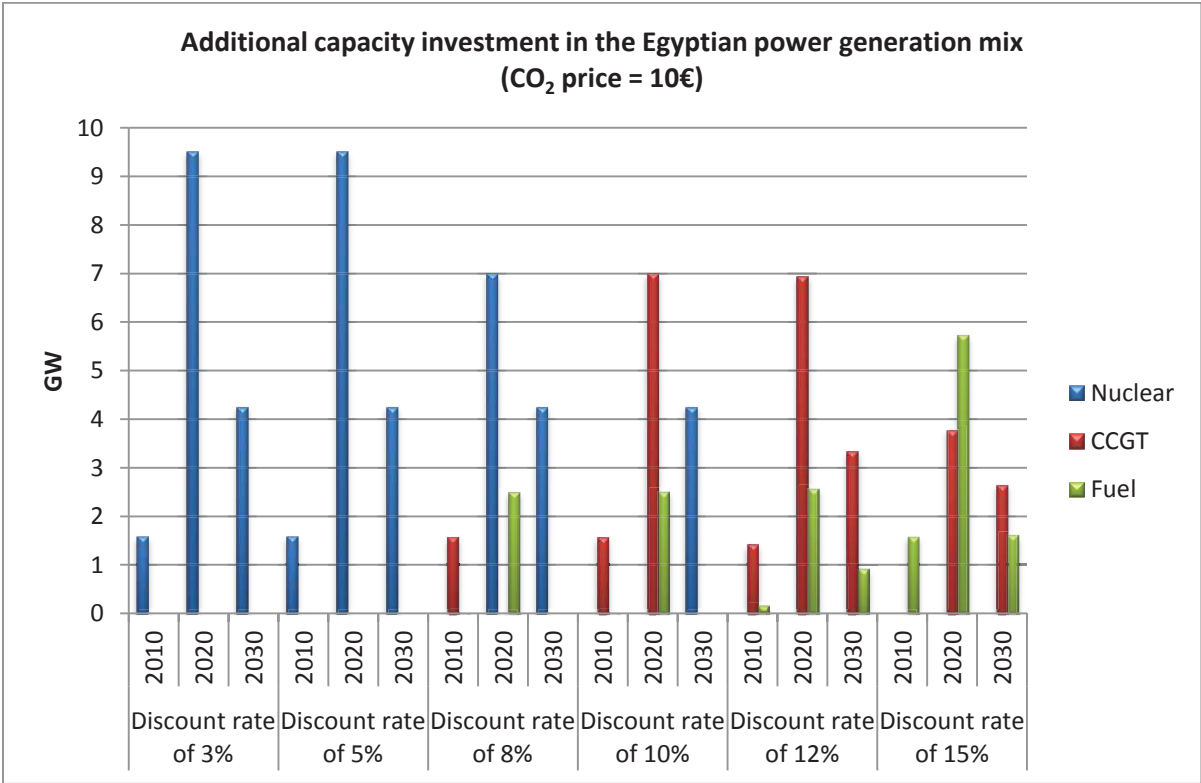


Figure 2-11

For the discount rates up to 5%, nuclear power remains again the most optimal choice and other technologies are not competitive at all (except as a back-up plant to compensate renewable intermittencies). Significant modification compare to the pervious case (without



emissions) can be noted in the discount range of 8% to 10%. In this range, nuclear energy is still present as an economical source of power; for instance around 8% of discount rate, nuclear energy could provide up to 70% of total electricity of Egypt as a most optimal power unit. However fossil plants start to occupy a bigger share in the power generation mix of the country in 10% discount rate case.

Uncertainty about climate policy is one of the greatest risk factors that investors in power sectors are dealt with at the moment. Climate policy may have a weighty impact on power generation costs with different options. If ambitious carbon reductions are to be achieved globally, the power sector may need to be rapidly decarbonized in many regions. However, the decarbonisation trend observed in non-OECDs is much slower than that of OECDs. Uncertainty about future climate policy (hereby defined by various CO<sub>2</sub> prices) thereby creates significant insecurity about generation costs of different technologies.

Hence, a sensitivity analysis designed for different CO<sub>2</sub> prices so as to better demonstrate the impact of carbon price increase on the power generation structure of Egypt and obviously the promotion of non CO<sub>2</sub>-emitting technologies compare to fossil fuel based ones. Figure 2-12 shows Egyptian optimal generation capacity additions proposed by the model under different CO<sub>2</sub> price scenarios.

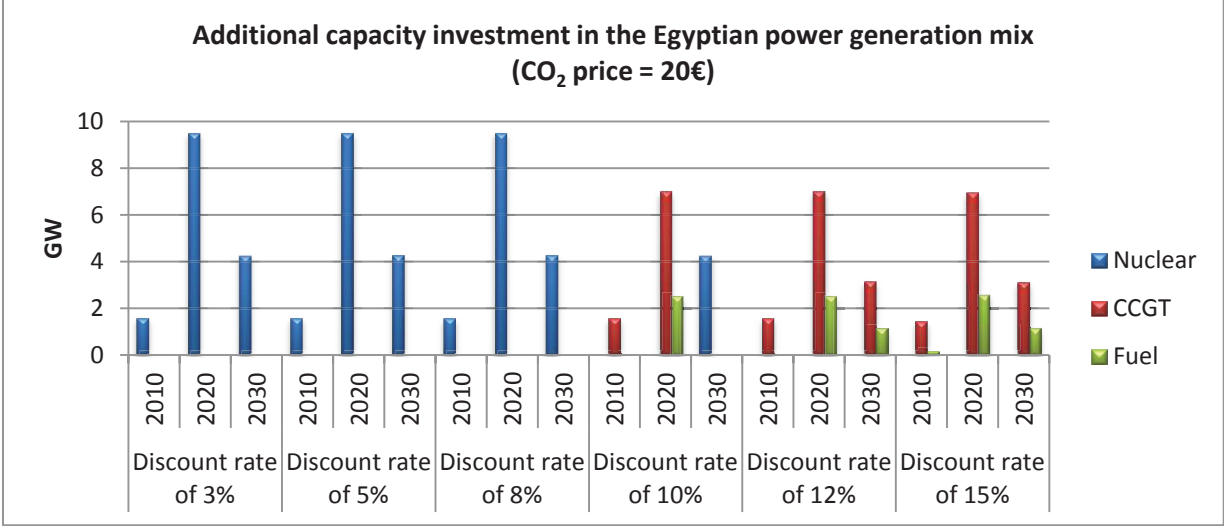
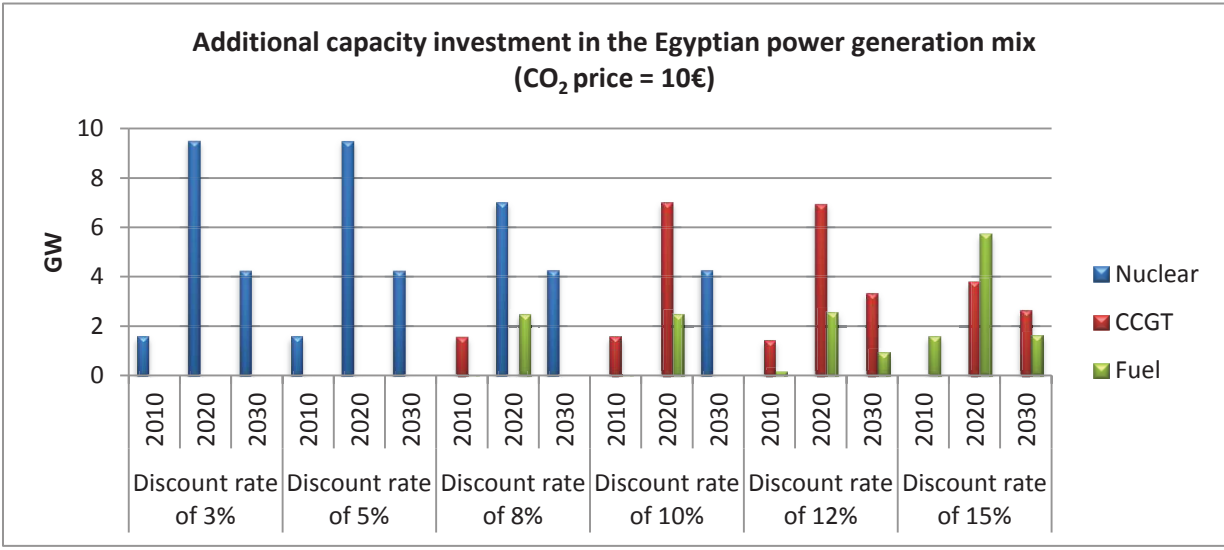
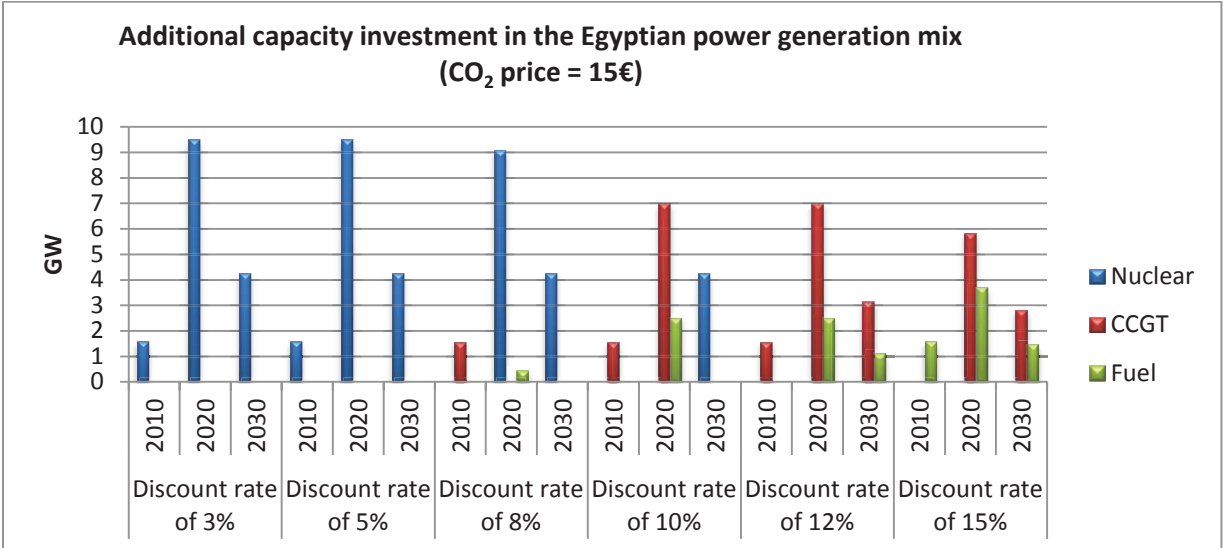


Figure 2-12

Finally, it is important to mention that Egypt became a net importer of oil in 2010 (our reference year). In our model we assume that fossil fuel prices (oil and gas) are equal to that of international markets. Hence, if Egypt continues to provide natural gas to power producers under subsidies (with final price lower than that of international markets), all the suggested investments in fuel power plants should be replaced by gas units. This could become also applicable for nuclear units after certain level of subsidies. And on the contrary, under total subsidy-suppression scenario in addition to less uncertain investment and political environment (leading to smaller discount rates) nuclear power choice could be the most economic and optimal solution. Not only it will provide cheaper power, but also help to free certain share of domestic gas production for export into international markets. Nevertheless, we should not forget that certain amount of power (almost 20% according to our model) must be still afforded by fossil fuel plants, with very rapid start-up time, to play the back-up role for the 20% integration of intermittent renewables in the Egyptian electricity mix.

Last but not the list, we should mention that the fuel prices, for oil and gas (indexed mainly on the oil price), are also very important inputs of our model and their variation can highly impact the result. Henceforth, we also performed a sensitivity analysis over the oil price variation in the international markets so as to reveal its impact on the investment in various technologies.

This was done only for the median case of 8% discount rate which is the most probable and common one in the Egyptian electricity systems. The results are given in the figure 2-13 for a variation range of 30% in both negative and positive directions. We have considered only the investments done up to 2020 and 2030 as the price variation is not applicable to the investment decision of the year 2010 which is already done under the assumption of 80\$/bbl for the oil price. This is also true in reality as the oil price variations can impact the investment decisions (in the power sector) only in the medium and long terms and not in the very short term due to the technical challenges associated with technological transitions.

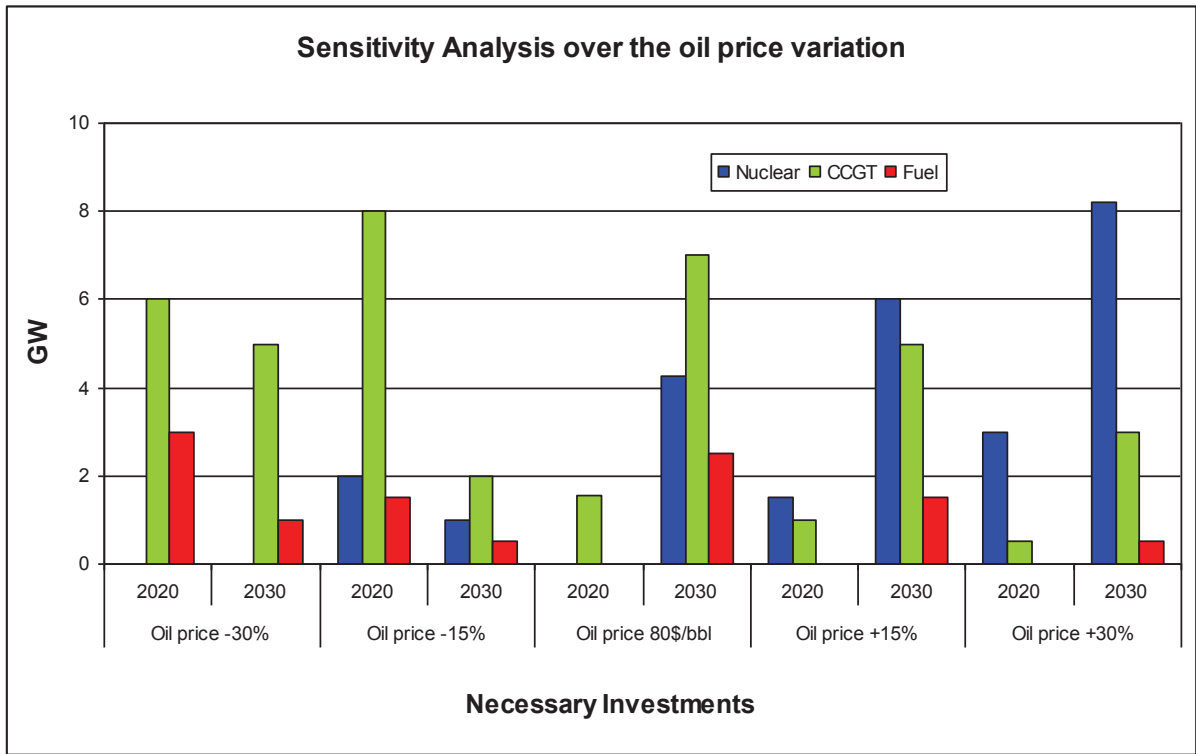


Figure 2-13

As we observe in the figure, an oil price increase will heavily boost the investments in nuclear power units in both medium and long terms while fuel power stations won't be profitable anymore. This is mainly the case for the case of 30% increase of oil price, as there is only a tiny portion of investment in 2030 contains fuel power plants which will be mainly used as back-up and peak-shaving units. On the contrary, for the case of oil price drop, down to -15% and -30%, the nuclear would become the most non-optimal power unit whereas CCGT plants are the most recommended options in parallel with fuel units running by oil and oil products.

## **Conclusion**

Our cost, investment and sensitivity analysis of the Egyptian's current and future power generation mix and demands demonstrate the unfeasibility (from an economic point of view of course) of being entirely dependent on national fossil fuel reserves so as to meet the electricity generation needs of the country.

Efficient utilization of the energy resources concerning the electricity sector requires a considerable promotion of the alternative non-fossil techniques. Moreover, investment in nuclear power units for the demand satisfaction of the next 20 years (between 2020 and 2030) in addition to 20% integration of renewables in the generation mix can reduce the CO<sub>2</sub> emission of the Egyptian power sector by almost 25 million tonnes per year.

Even though the renewable sources of power generation can be used efficiently at very decentralized and local scales, yet intermittent nature of these technologies does not permit to provide a large scale continuous base-load power. Besides, the need for more fossil-fuel-based back-up power plants would become inevitable to guarantee the national power system equilibrium.

Therefore, a power generation strategy based on a gradual integration of nuclear and renewable is suggested. A power generation mix, based on an optimal choice of fossil, nuclear, hydraulic and other renewables, is considered to be the most appropriate way of electricity production in Egypt.

**Appendix 2-A**

***Single Buyer Model***

In this restructured electricity market, networks (whether transmission or distribution) remain regulated while generation is exposed to competition. For the networks the incentives for capital investments are function of the regulation imposed by the regulatory authorities. Contrarily in the case of generation no explicit price control applies, nevertheless the regulators may monitor generation adequacy and establish additional market and tariff-based incentives to encourage new investments in the sector.

Under a single buyer model only new capacity development is exposed to competition, while the continued operation of plants with respect to output would be exempt from competition and would rather run under (usually long-term) power purchase agreements. The single buyer is responsible to determine capacity requirements and could also direct the technology decision through suitable conditions included in the call for tender for new capacity.

In this model the revenue that a generator is allowed to receive under its contract with the single buyer is normally contains two main components, availability payments and energy payments. The energy payments are intended, among other things, to recompense the generator for the costs associated with operating the plant, that is fuel and variable O&M costs. The availability payments are anticipated to provide the generator with revenue to cover the cost of capital, including a normal rate of return, and the fixed O&M costs.

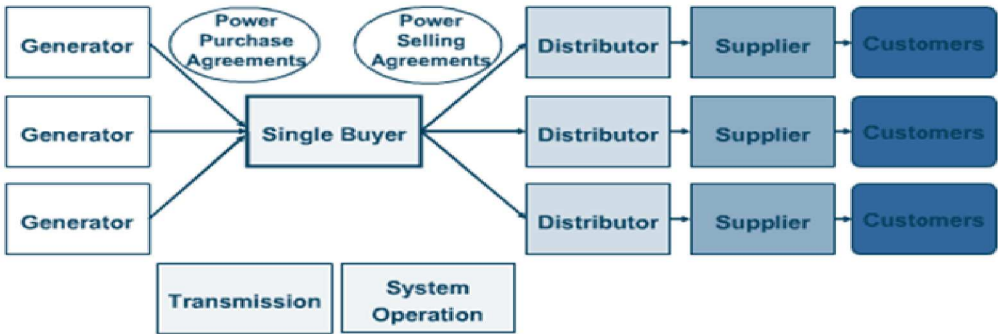


Figure 2-12: Single Buyer Electricity Market  
(Source: KEMA)

## Appendix 2-B

### *Egyptian power generation model's equations in GAMS*

#### 1 7 4 **Equat i ons**

1 7 6 cost

1 7 7 suppl y(i uni t , PH, season, ALEA, t i me)

1 7 8 demand( PH, season, ALEA, t i me)

1 7 9 capaci ty(i uni t , season, t i me)

1 8 0 capi nst 1(i uni t )

1 8 1 capi nst 2(i uni t )

1 8 2 capi nst 3(i uni t )

1 8 3 emi sco2(i uni t co2, ph, season, al ea, t i me)

1 8 6 cost ..

z=e=sum( (i uni t , PH, season, ALEA, t i me) , pr obal ea( al ea) \* gamma( t i me) \* vcost ( »  
i uni t ) \* PUI SS( i uni t , PH, season, ALEA, t i me) \* dur ee( PH, season) ) +

sum( (i uni t , PH, season, ALEA, t i me) , f cost ( i uni t ) \* phi ( t i me) \* capel ec( i uni t , t i me) )

+sum( (i uni t co2, PH, season, al ea, t i me) , pr obal ea( al ea) \* gamma( t i me) \* emi s( i uni t co  
2, »

PH, season, al ea, t i me) \* pr i xco2);

1 9 0 suppl y(i uni t , PH, season, ALEA, t i me) .. PUI SS( i uni t , PH, season, ALEA, t i me)  
=| = CAP»

AVAI BLE( i uni t , sEAs on, t i me);

1 9 2 demand( PH, season, ALEA, t i me) ..

sum( (i uni t ) , PUI SS( i uni t , PH, season, ALEA, t i me) ) =>

g=DEMNET( PH, season, ALEA, t i me);

1 9 4 capaci ty(i uni t , season, t i me) .. CAPAvai bl e( i uni t , season, t i me) -  
capel ec( i uni t , t »

i me) \* di spo( i uni t , season) =e= 0;

1 9 5

1 9 6 capi nst 1( i uni t ) .. capel ec( i uni t , ' 2010' ) - CAPI NI ( i uni t ) -  
i nv( i uni t , ' 2010' »

) =e= 0;

1 9 7

1 9 8 capi nst 2( i uni t ) .. capel ec( i uni t , ' 2020' ) - capel ec( i uni t , ' 2010' ) -  
i nv( i uni t , ' »

2020' ) =e= 0;

1 9 9

2 0 0 capi nst 3( i uni t ) .. capel ec( i uni t , ' 2030' ) - capel ec( i uni t , ' 2020' ) -  
i nv( i uni t , ' »

2030' ) =e= 0;

2 0 2 emi sco2( i uni t co2, ph, season, al ea, t i me) ..

pui ss( i uni t co2, ph, season, al ea, t i me) \* »

f act emi s( i uni t co2) \* dur ee( ph, season) -

emi s( i uni t co2, ph, season, al ea, t i me) =e=0. ;

2 0 5 **Model** El ec / al l / ;

2 0 6 **Solve** El ec usi ng l p mi ni mi zi ng z ;

2 0 8 **execut e\_unl oad** ' resul t s. gdx' , capavai bl e, i nv;

## Appendix 2-C

### *Egyptian power generation model's output in GAMS*

```
2 3 0 G e n e r a l   A l g e b r a i c   M o d e l i n g   S y s t e m
2 3 1 E x e c u t i o n
2 3 2
2 3 3
2 3 4 ---- 119 PARAMETER Derrel ect
( E l e c t r i c i t y   D e m a n d )
2 3 5
2 3 6 I N D E X 1 = p1
2 3 7
2 3 8 2010 2020 2030
2 3 9
2 4 0 s1. a1 79.200 87.120 95.040
2 4 1 s1. a2 71.380 78.518 85.656
2 4 2 s1. a3 83.880 92.268 100.656
2 4 3
2 4 4 I N D E X 1 = p2
2 4 5
2 4 6 2010 2020 2030
2 4 7
2 4 8 s1. a1 73.070 80.377 87.684
2 4 9 s1. a2 71.380 78.518 85.656
2 5 0 s1. a3 74.430 81.873 89.316
2 5 1 s2. a1 66.390 73.029 79.668
2 5 2 s2. a2 65.400 71.940 78.480
2 5 3 s2. a3 66.320 72.952 79.584
2 5 4 s3. a1 53.610 58.971 64.332
2 5 5 s3. a2 53.360 58.696 64.032
2 5 6 s3. a3 53.300 58.630 63.960
2 5 7
2 5 8 I N D E X 1 = p3
2 5 9
2 6 0 2010 2020 2030
2 6 1
2 6 2 s1. a1 61.580 67.738 73.896
2 6 3 s1. a2 60.390 66.429 72.468
2 6 4 s1. a3 61.030 67.133 73.236
2 6 5 s2. a1 57.900 63.690 69.480
2 6 6 s2. a2 57.080 62.788 68.496
2 6 7 s2. a3 57.410 63.151 68.892
2 6 8 s3. a1 46.830 51.513 56.196
2 6 9 s3. a2 46.890 51.579 56.268
2 7 0 s3. a3 46.890 51.579 56.268
2 7 1 s4. a1 39.710 43.681 47.652
2 7 2 s4. a2 39.710 43.681 47.652
2 7 3 s4. a3 39.570 43.527 47.484
2 7 4
2 7 5 GAMS 24.4.1 r50296 Released Dec 20,
2014 VEX-WEI x86 64bit/MS Windows
1 5 6 0 Model Statistics SOLVE El ec Usi ng
LP From line 206
1 5 6 1
1 5 6 2
1 5 6 3 M O D E L   S T A T I S T I C S
1 5 6 4
1 5 6 5 B L O C K S   O F   E Q U A T I O N S   8   S I N G L E
E Q U A T I O N S   1, 048
1 5 6 6 B L O C K S   O F   V A R I A B L E S   6   S I N G L E
V A R I A B L E S   955
1 5 6 7 N O N   Z E R O   E L E M E N T S   3, 020
1 5 6 8
1 5 7 9 S O L V E S U M M A R Y
1 5 8 0
1 5 8 1 M O D E L   E l e c   O B J E C T I V E   z
1 5 8 2 T Y P E   L P   D I R E C T I O N   M I N I M I Z E
1 5 8 3 S O L V E R   C P L E X   F R O M   L I N E   206
1 5 8 4
1 5 8 5 **** SOLVER STATUS 1 Normal
Compl etion
1 5 8 6 **** MODEL STATUS 1 Optimal
1 5 8 7 **** OBJECTIVE VALUE
237523802793.0113
1 5 8 8
1 5 8 9 RESOURCE USAGE, L I M I T 0.047
1000.000
1 5 9 0 I T E R A T I O N   C O U N T,   L I M I T 232
2000000000
1 5 9 1
1 5 9 2 I B M   I L O G   C P L E X   24.4.1 r50296
Released Dec 20, 2014 WEI x86 64bit/MS
Windows»
1 5 9 3 --- GAMS/ Cplex licensed for
continuous and discrete problems.
1 5 9 4 Cplex 12.6.1.0
1 5 9 5
1 5 9 6 Space for names approximat ely 0.06
Mb
1 5 9 7 Use option 'names no' to turn use
of names off
1 5 9 8 LP status(1): opti mal
```



1 5 9 9 Cpl ex Ti me: 0.01sec (det . 1.96  
 ticks)  
 1 6 0 0 Optimal solution found.  
 1 6 0 1 Objective : 237523802793.011260

**2 6 9 0 ---- VAR Pui ss**

**(Power loaded on the grid for each season,  
 hour and from each technology under each  
 random status)**

2 6 9 1  
 2 6 9 2 LOWER LEVEL UPPER MARGI NAL  
 2 6 9 3  
 2 6 9 4 NC. p1. s1. a1. 2010 . 53.720 +I NF .  
 2 6 9 5 NC. p1. s1. a1. 2020 . 56.967 +I NF .  
 2 6 9 6 NC. p1. s1. a1. 2030 . 64.348 +I NF .  
 2 6 9 7 NC. p1. s1. a2. 2010 . 53.720 +I NF .  
 2 6 9 8 NC. p1. s1. a2. 2020 . 56.967 +I NF .  
 2 6 9 9 NC. p1. s1. a2. 2030 . 64.348 +I NF .  
 2 7 0 0 NC. p1. s1. a3. 2010 . 53.720 +I NF .  
 2 7 0 1 NC. p1. s1. a3. 2020 . 56.967 +I NF .  
 2 7 0 2 NC. p1. s1. a3. 2030 . 64.348 +I NF .  
 2 7 0 3 NC. p1. s2. a1. 2010 . 53.720 +I NF .  
 2 7 0 4 NC. p1. s2. a1. 2020 . 56.967 +I NF .  
 2 7 0 5 NC. p1. s2. a1. 2030 . 64.348 +I NF .  
 2 7 0 6 NC. p1. s2. a2. 2010 . 53.720 +I NF .  
 2 7 0 7 NC. p1. s2. a2. 2020 . 56.967 +I NF .  
 2 7 0 8 NC. p1. s2. a2. 2030 . 64.348 +I NF .  
 2 7 0 9 NC. p1. s2. a3. 2010 . 53.720 +I NF .  
 2 7 1 0 NC. p1. s2. a3. 2020 . 56.967 +I NF .  
 2 7 1 1 NC. p1. s2. a3. 2030 . 64.348 +I NF .  
 2 7 1 2 NC. p1. s3. a1. 2010 . 37.920 +I NF .  
 2 7 1 3 NC. p1. s3. a1. 2020 . 40.212 +I NF .  
 2 7 1 4 NC. p1. s3. a1. 2030 . 45.422 +I NF .  
 2 7 1 5 NC. p1. s3. a2. 2010 . 37.920 +I NF .  
 2 7 1 6 NC. p1. s3. a2. 2020 . 40.212 +I NF .  
 2 7 1 7 NC. p1. s3. a2. 2030 . 45.422 +I NF .  
 2 7 1 8 NC. p1. s3. a3. 2010 . 37.920 +I NF .  
 2 7 1 9 NC. p1. s3. a3. 2020 . 40.212 +I NF .  
 2 7 2 0 NC. p1. s3. a3. 2030 . 45.422 +I NF .  
 2 7 2 1 NC. p1. s4. a1. 2010 . 37.920 +I NF .  
 2 7 2 2 NC. p1. s4. a1. 2020 . 40.212 +I NF .  
 2 7 2 3 NC. p1. s4. a1. 2030 . 45.422 +I NF .  
 2 7 2 4 NC. p1. s4. a2. 2010 . 37.920 +I NF .  
 2 7 2 5 NC. p1. s4. a2. 2020 . 40.212 +I NF .  
 2 7 2 6 NC. p1. s4. a2. 2030 . 45.422 +I NF .  
 2 7 2 7 NC. p1. s4. a3. 2010 . 37.920 +I NF .  
 2 7 2 8 NC. p1. s4. a3. 2020 . 40.212 +I NF .

2 7 2 9 NC. p1. s4. a3. 2030 . 45.422 +I NF .  
 2 7 3 0 NC. p2. s1. a1. 2010 . 53.720 +I NF .  
 2 7 3 1 NC. p2. s1. a1. 2020 . 56.967 +I NF .  
 2 7 3 2 NC. p2. s1. a1. 2030 . 64.348 +I NF .  
 2 7 3 3 NC. p2. s1. a2. 2010 . 53.720 +I NF .  
 2 7 3 4 NC. p2. s1. a2. 2020 . 56.967 +I NF .  
 2 7 3 5 NC. p2. s1. a2. 2030 . 64.348 +I NF .  
 2 7 3 6 NC. p2. s1. a3. 2010 . 53.720 +I NF .  
 2 7 3 7 NC. p2. s1. a3. 2020 . 56.967 +I NF .  
 2 7 3 8 NC. p2. s1. a3. 2030 . 64.348 +I NF .  
 2 7 3 9 NC. p2. s2. a1. 2010 . 53.720 +I NF .  
 2 7 4 0 NC. p2. s2. a1. 2020 . 56.967 +I NF .  
 2 7 4 1 NC. p2. s2. a1. 2030 . 64.348 +I NF .  
 2 7 4 2 NC. p2. s2. a2. 2010 . 53.720 +I NF .  
 2 7 4 3 NC. p2. s2. a2. 2020 . 56.967 +I NF .  
 2 7 4 4 NC. p2. s2. a2. 2030 . 64.348 +I NF .  
 2 7 4 5 NC. p2. s2. a3. 2010 . 53.720 +I NF .  
 2 7 4 6 NC. p2. s2. a3. 2020 . 56.967 +I NF .  
 2 7 4 7 NC. p2. s2. a3. 2030 . 64.348 +I NF .  
 2 7 4 8 NC. p2. s3. a1. 2010 . 37.920 +I NF .  
 2 7 4 9 NC. p2. s3. a1. 2020 . 40.212 +I NF .  
 2 7 5 0 NC. p2. s3. a1. 2030 . 45.422 +I NF .  
 2 7 5 1 NC. p2. s3. a2. 2010 . 37.920 +I NF .  
 2 7 5 2 NC. p2. s3. a2. 2020 . 40.212 +I NF .  
 2 7 5 3 NC. p2. s3. a2. 2030 . 45.422 +I NF .  
 2 7 5 4 NC. p2. s3. a3. 2010 . 37.920 +I NF .  
 2 7 5 5 NC. p2. s3. a3. 2020 . 40.212 +I NF .  
 2 7 5 6 NC. p2. s3. a3. 2030 . 45.422 +I NF .  
 2 7 5 7 NC. p2. s4. a1. 2010 . 37.920 +I NF .  
 2 7 5 8 NC. p2. s4. a1. 2020 . 40.212 +I NF .  
 2 7 5 9 NC. p2. s4. a1. 2030 . 45.422 +I NF .  
 2 7 6 0 NC. p2. s4. a2. 2010 . 37.920 +I NF .  
 2 7 6 1 NC. p2. s4. a2. 2020 . 40.212 +I NF .  
 2 7 6 2 NC. p2. s4. a2. 2030 . 45.422 +I NF .  
 2 7 6 3 NC. p2. s4. a3. 2010 . 37.920 +I NF .  
 2 7 6 4 NC. p2. s4. a3. 2020 . 40.212 +I NF .  
 2 7 6 5 NC. p2. s4. a3. 2030 . 45.422 +I NF .  
 2 7 6 6 NC. p3. s1. a1. 2010 . 53.510 +I NF .  
 2 7 6 7 NC. p3. s1. a1. 2020 . 56.967 +I NF .  
 2 7 6 8 NC. p3. s1. a1. 2030 . 64.348 +I NF .  
 2 7 6 9 NC. p3. s1. a2. 2010 . 52.463 +I NF .  
 2 7 7 0 NC. p3. s1. a2. 2020 . 56.967 +I NF .  
 2 7 7 1 NC. p3. s1. a2. 2030 . 63.092 +I NF .  
 2 7 7 2 NC. p3. s1. a3. 2010 . 53.026 +I NF .  
 2 7 7 3 NC. p3. s1. a3. 2020 . 56.967 +I NF .  
 2 7 7 4 NC. p3. s1. a3. 2030 . 63.768 +I NF .  
 2 7 7 5 NC. p3. s2. a1. 2010 . 50.272 +I NF .

2 7 7 6 NC. p3. s2. a1. 2020 .	55. 367 +I NF .	2 8 2 3 TH. p1. s3. a2. 2010 .	10. 160 +I NF .
2 7 7 7 NC. p3. s2. a1. 2030 .	60. 462 +I NF .	2 8 2 4 TH. p1. s3. a2. 2020 .	10. 160 +I NF .
2 7 7 8 NC. p3. s2. a2. 2010 .	49. 550 +I NF .	2 8 2 5 TH. p1. s3. a2. 2030 .	10. 160 +I NF .
2 7 7 9 NC. p3. s2. a2. 2020 .	54. 573 +I NF .	2 8 2 6 TH. p1. s3. a3. 2010 .	10. 160 +I NF .
2 7 8 0 NC. p3. s2. a2. 2030 .	59. 596 +I NF .	2 8 2 7 TH. p1. s3. a3. 2020 .	10. 160 +I NF .
2 7 8 1 NC. p3. s2. a3. 2010 .	49. 841 +I NF .	2 8 2 8 TH. p1. s3. a3. 2030 .	10. 160 +I NF .
2 7 8 2 NC. p3. s2. a3. 2020 .	54. 893 +I NF .	2 8 2 9 TH. p1. s4. a1. 2010 .	10. 160 +I NF .
2 7 8 3 NC. p3. s2. a3. 2030 .	59. 945 +I NF .	2 8 3 0 TH. p1. s4. a1. 2020 .	10. 160 +I NF .
2 7 8 4 NC. p3. s3. a1. 2010 .	37. 920 +I NF .	2 8 3 1 TH. p1. s4. a1. 2030 .	10. 160 +I NF .
2 7 8 5 NC. p3. s3. a1. 2020 .	40. 212 +I NF .	2 8 3 2 TH. p1. s4. a2. 2010 .	10. 160 +I NF .
2 7 8 6 NC. p3. s3. a1. 2030 .	45. 422 +I NF .	2 8 3 3 TH. p1. s4. a2. 2020 .	10. 160 +I NF .
2 7 8 7 NC. p3. s3. a2. 2010 .	37. 920 +I NF .	2 8 3 4 TH. p1. s4. a2. 2030 .	10. 160 +I NF .
2 7 8 8 NC. p3. s3. a2. 2020 .	40. 212 +I NF .	2 8 3 5 TH. p1. s4. a3. 2010 .	10. 160 +I NF .
2 7 8 9 NC. p3. s3. a2. 2030 .	45. 422 +I NF .	2 8 3 6 TH. p1. s4. a3. 2020 .	10. 160 +I NF .
2 7 9 0 NC. p3. s3. a3. 2010 .	37. 920 +I NF .	2 8 3 7 TH. p1. s4. a3. 2030 .	10. 160 +I NF .
2 7 9 1 NC. p3. s3. a3. 2020 .	40. 212 +I NF .	2 8 3 8 TH. p2. s1. a1. 2010 .	9. 902 +I NF .
2 7 9 2 NC. p3. s3. a3. 2030 .	45. 422 +I NF .	2 8 3 9 TH. p2. s1. a1. 2020 .	11. 430 +I NF .
2 7 9 3 NC. p3. s4. a1. 2010 .	34. 265 +I NF .	2 8 4 0 TH. p2. s1. a1. 2030 .	11. 430 +I NF .
2 7 9 4 NC. p3. s4. a1. 2020 .	37. 759 +I NF .	2 8 4 1 TH. p2. s1. a2. 2010 .	8. 414 +I NF .
2 7 9 5 NC. p3. s4. a1. 2030 .	41. 254 +I NF .	2 8 4 2 TH. p2. s1. a2. 2020 .	11. 430 +I NF .
2 7 9 6 NC. p3. s4. a2. 2010 .	34. 265 +I NF .	2 8 4 3 TH. p2. s1. a2. 2030 .	10. 349 +I NF .
2 7 9 7 NC. p3. s4. a2. 2020 .	37. 759 +I NF .	2 8 4 4 TH. p2. s1. a3. 2010 .	11. 098 +I NF .
2 7 9 8 NC. p3. s4. a2. 2030 .	41. 254 +I NF .	2 8 4 5 TH. p2. s1. a3. 2020 .	11. 430 +I NF .
2 7 9 9 NC. p3. s4. a3. 2010 .	34. 142 +I NF .	2 8 4 6 TH. p2. s1. a3. 2030 .	11. 430 +I NF .
2 8 0 0 NC. p3. s4. a3. 2020 .	37. 624 +I NF .	2 8 4 7 TH. p2. s2. a1. 2010 .	4. 023 +I NF .
2 8 0 1 NC. p3. s4. a3. 2030 .	41. 106 +I NF .	2 8 4 8 TH. p2. s2. a1. 2020 .	6. 618 +I NF .
2 8 0 2 TH. p1. s1. a1. 2010 .	11. 430 +I NF .	2 8 4 9 TH. p2. s2. a1. 2030 .	5. 079 +I NF .
2 8 0 3 TH. p1. s1. a1. 2020 .	11. 430 +I NF .	2 8 5 0 TH. p2. s2. a2. 2010 .	3. 152 +I NF .
2 8 0 4 TH. p1. s1. a1. 2030 .	11. 430 +I NF .	2 8 5 1 TH. p2. s2. a2. 2020 .	5. 660 +I NF .
2 8 0 5 TH. p1. s1. a2. 2010 .	8. 414 +I NF .	2 8 5 2 TH. p2. s2. a2. 2030 .	4. 034 +I NF .
2 8 0 6 TH. p1. s1. a2. 2020 .	11. 430 +I NF .	2 8 5 3 TH. p2. s2. a3. 2010 .	3. 962 +I NF .
2 8 0 7 TH. p1. s1. a2. 2030 .	10. 349 +I NF .	2 8 5 4 TH. p2. s2. a3. 2020 .	6. 551 +I NF .
2 8 0 8 TH. p1. s1. a3. 2010 .	11. 430 +I NF .	2 8 5 5 TH. p2. s2. a3. 2030 .	5. 005 +I NF .
2 8 0 9 TH. p1. s1. a3. 2020 .	11. 430 +I NF .	2 8 5 6 TH. p2. s3. a1. 2010 .	8. 577 +I NF .
2 8 1 0 TH. p1. s1. a3. 2030 .	11. 430 +I NF .	2 8 5 7 TH. p2. s3. a1. 2020 .	10. 160 +I NF .
2 8 1 1 TH. p1. s2. a1. 2010 .	11. 430 +I NF .	2 8 5 8 TH. p2. s3. a1. 2030 .	10. 160 +I NF .
2 8 1 2 TH. p1. s2. a1. 2020 .	11. 430 +I NF .	2 8 5 9 TH. p2. s3. a2. 2010 .	8. 357 +I NF .
2 8 1 3 TH. p1. s2. a1. 2030 .	11. 430 +I NF .	2 8 6 0 TH. p2. s3. a2. 2020 .	10. 160 +I NF .
2 8 1 4 TH. p1. s2. a2. 2010 .	11. 430 +I NF .	2 8 6 1 TH. p2. s3. a2. 2030 .	10. 160 +I NF .
2 8 1 5 TH. p1. s2. a2. 2020 .	11. 430 +I NF .	2 8 6 2 TH. p2. s3. a3. 2010 .	8. 304 +I NF .
2 8 1 6 TH. p1. s2. a2. 2030 .	11. 430 +I NF .	2 8 6 3 TH. p2. s3. a3. 2020 .	10. 160 +I NF .
2 8 1 7 TH. p1. s2. a3. 2010 .	11. 430 +I NF .	2 8 6 4 TH. p2. s3. a3. 2030 .	10. 160 +I NF .
2 8 1 8 TH. p1. s2. a3. 2020 .	11. 430 +I NF .	2 8 6 5 TH. p2. s4. a1. 2010 .	10. 160 +I NF .
2 8 1 9 TH. p1. s2. a3. 2030 .	11. 430 +I NF .	2 8 6 6 TH. p2. s4. a1. 2020 .	10. 160 +I NF .
2 8 2 0 TH. p1. s3. a1. 2010 .	10. 160 +I NF .	2 8 6 7 TH. p2. s4. a1. 2030 .	10. 160 +I NF .
2 8 2 1 TH. p1. s3. a1. 2020 .	10. 160 +I NF .	2 8 6 8 TH. p2. s4. a2. 2010 .	10. 160 +I NF .
2 8 2 2 TH. p1. s3. a1. 2030 .	10. 160 +I NF .	2 8 6 9 TH. p2. s4. a2. 2020 .	10. 160 +I NF .

2 8 7 0 TH p2. s4. a2. 2030 . 10. 160 +I NF .	2 9 1 7 CG p1. s1. a3. 2020 . 10. 679 +I NF .
2 8 7 1 TH p2. s4. a3. 2010 . 10. 160 +I NF .	2 9 1 8 CG p1. s1. a3. 2030 . 10. 679 +I NF .
2 8 7 2 TH p2. s4. a3. 2020 . 10. 160 +I NF .	2 9 1 9 CG p1. s2. a1. 2010 . 6. 544 +I NF .
2 8 7 3 TH p2. s4. a3. 2030 . 10. 160 +I NF .	2 9 2 0 CG p1. s2. a1. 2020 . 10. 679 +I NF .
2 8 7 4 TH p3. s1. a1. 2010 . . +I NF 1. 9844E+8	2 9 2 1 CG p1. s2. a1. 2030 . 10. 679 +I NF .
2 8 7 5 TH p3. s1. a1. 2020 . 1. 962 +I NF .	2 9 2 2 CG p1. s2. a2. 2010 . 6. 544 +I NF .
2 8 7 6 TH p3. s1. a1. 2030 . . +I NF 6. 1353E+7	2 9 2 3 CG p1. s2. a2. 2020 . 10. 679 +I NF .
2 8 7 7 TH p3. s1. a2. 2010 . . +I NF 2. 4805E+7	2 9 2 4 CG p1. s2. a2. 2030 . 10. 679 +I NF .
2 8 7 8 TH p3. s1. a2. 2020 . 0. 810 +I NF .	2 9 2 5 CG p1. s2. a3. 2010 . 6. 544 +I NF .
2 8 7 9 TH p3. s1. a2. 2030 . . +I NF 7. 7870E+6	2 9 2 6 CG p1. s2. a3. 2020 . 10. 679 +I NF .
2 8 8 0 TH p3. s1. a3. 2010 . . +I NF 2. 4805E+7	2 9 2 7 CG p1. s2. a3. 2030 . 10. 679 +I NF .
2 8 8 1 TH p3. s1. a3. 2020 . 1. 430 +I NF .	2 9 2 8 CG p1. s3. a1. 2010 . 5. 817 +I NF .
2 8 8 2 TH p3. s1. a3. 2030 . . +I NF 7. 7870E+6	2 9 2 9 CG p1. s3. a1. 2020 . 9. 492 +I NF .
2 8 8 3 TH p3. s2. a1. 2010 . . +I NF 1. 3732E+8	2 9 3 0 CG p1. s3. a1. 2030 . 9. 492 +I NF .
2 8 8 4 TH p3. s2. a1. 2020 . . +I NF 6. 3608E+7	2 9 3 1 CG p1. s3. a2. 2010 . 5. 817 +I NF .
2 8 8 5 TH p3. s2. a1. 2030 . . +I NF 4. 3109E+7	2 9 3 2 CG p1. s3. a2. 2020 . 9. 492 +I NF .
2 8 8 6 TH p3. s2. a2. 2010 . . +I NF 1. 7166E+7	2 9 3 3 CG p1. s3. a2. 2030 . 9. 492 +I NF .
2 8 8 7 TH p3. s2. a2. 2020 . . +I NF 7. 9510E+6	2 9 3 4 CG p1. s3. a3. 2010 . 5. 817 +I NF .
2 8 8 8 TH p3. s2. a2. 2030 . . +I NF 5. 3887E+6	2 9 3 5 CG p1. s3. a3. 2020 . 9. 492 +I NF .
2 8 8 9 TH p3. s2. a3. 2010 . . +I NF 1. 7166E+7	2 9 3 6 CG p1. s3. a3. 2030 . 9. 492 +I NF .
2 8 9 0 TH p3. s2. a3. 2020 . . +I NF 7. 9510E+6	2 9 3 7 CG p1. s4. a1. 2010 . 5. 817 +I NF .
2 8 9 1 TH p3. s2. a3. 2030 . . +I NF 5. 3887E+6	2 9 3 8 CG p1. s4. a1. 2020 . 9. 492 +I NF .
2 8 9 2 TH p3. s3. a1. 2010 . 2. 610 +I NF .	2 9 3 9 CG p1. s4. a1. 2030 . 9. 492 +I NF .
2 8 9 3 TH p3. s3. a1. 2020 . 4. 439 +I NF .	2 9 4 0 CG p1. s4. a2. 2010 . 5. 817 +I NF .
2 8 9 4 TH p3. s3. a1. 2030 . 3. 350 +I NF .	2 9 4 1 CG p1. s4. a2. 2020 . 9. 492 +I NF .
2 8 9 5 TH p3. s3. a2. 2010 . 2. 663 +I NF .	2 9 4 2 CG p1. s4. a2. 2030 . 9. 492 +I NF .
2 8 9 6 TH p3. s3. a2. 2020 . 4. 497 +I NF .	2 9 4 3 CG p1. s4. a3. 2010 . 5. 817 +I NF .
2 8 9 7 TH p3. s3. a2. 2030 . 3. 413 +I NF .	2 9 4 4 CG p1. s4. a3. 2020 . 9. 492 +I NF .
2 8 9 8 TH p3. s3. a3. 2010 . 2. 663 +I NF .	2 9 4 5 CG p1. s4. a3. 2030 . 9. 492 +I NF .
2 8 9 9 TH p3. s3. a3. 2020 . 4. 497 +I NF .	2 9 4 6 CG p2. s1. a1. 2010 . . +I NF 4. 6294E+7
2 9 0 0 TH p3. s3. a3. 2030 . 3. 413 +I NF .	2 9 4 7 CG p2. s1. a1. 2020 . 1. 655 +I NF .
2 9 0 1 TH p3. s4. a1. 2010 . . +I NF 2. 8420E+8	2 9 4 8 CG p2. s1. a1. 2030 . 0. 703 +I NF .
2 9 0 2 TH p3. s4. a1. 2020 . . +I NF 1. 3164E+8	2 9 4 9 CG p2. s1. a2. 2010 . . +I NF 5. 7868E+6
2 9 0 3 TH p3. s4. a1. 2030 . . +I NF 8. 9217E+7	2 9 5 0 CG p2. s1. a2. 2020 . 0. 019 +I NF .
2 9 0 4 TH p3. s4. a2. 2010 . . +I NF 3. 5525E+7	2 9 5 1 CG p2. s1. a2. 2030 . . +I NF 1. 8166E+6
2 9 0 5 TH p3. s4. a2. 2020 . . +I NF 1. 6455E+7	2 9 5 2 CG p2. s1. a3. 2010 . . +I NF 5. 7868E+6
2 9 0 6 TH p3. s4. a2. 2030 . . +I NF 1. 1152E+7	2 9 5 3 CG p2. s1. a3. 2020 . 2. 971 +I NF .
2 9 0 7 TH p3. s4. a3. 2010 . . +I NF 3. 5525E+7	2 9 5 4 CG p2. s1. a3. 2030 . 2. 140 +I NF .
2 9 0 8 TH p3. s4. a3. 2020 . . +I NF 1. 6455E+7	2 9 5 5 CG p2. s2. a1. 2010 . . +I NF 3. 9552E+7
2 9 0 9 TH p3. s4. a3. 2030 . . +I NF 1. 1152E+7	2 9 5 6 CG p2. s2. a1. 2020 . . +I NF 1. 8320E+7
2 9 1 0 CG p1. s1. a1. 2010 . 3. 866 +I NF .	2 9 5 7 CG p2. s2. a1. 2030 . . +I NF 1. 2416E+7
2 9 1 1 CG p1. s1. a1. 2020 . 7. 589 +I NF .	2 9 5 8 CG p2. s2. a2. 2010 . . +I NF 4. 9440E+6
2 9 1 2 CG p1. s1. a1. 2030 . 7. 177 +I NF .	2 9 5 9 CG p2. s2. a2. 2020 . . +I NF 2. 2900E+6
2 9 1 3 CG p1. s1. a2. 2010 . . +I NF 1. 6524E+6	2 9 6 0 CG p2. s2. a2. 2030 . . +I NF 1. 5520E+6
2 9 1 4 CG p1. s1. a2. 2020 . 0. 019 +I NF .	2 9 6 1 CG p2. s2. a3. 2010 . . +I NF 4. 9440E+6
2 9 1 5 CG p1. s1. a2. 2030 . . +I NF 5. 1873E+5	2 9 6 2 CG p2. s2. a3. 2020 . . +I NF 2. 2900E+6
2 9 1 6 CG p1. s1. a3. 2010 . 6. 544 +I NF .	2 9 6 3 CG p2. s2. a3. 2030 . . +I NF 1. 5520E+6

2 9 6 4	CG p2. s3. a1. 2010	. . +I NF 9. 9277E+7	3 0 1 1	CG p3. s4. a1. 2030	. . +I NF 1. 1402E+8
2 9 6 5	CG p2. s3. a1. 2020	. 0. 842 +I NF .	3 0 1 2	CG p3. s4. a2. 2010	. . +I NF 4. 5399E+7
2 9 6 6	CG p2. s3. a1. 2030	. 0. 350 +I NF .	3 0 1 3	CG p3. s4. a2. 2020	. . +I NF 2. 1029E+7
2 9 6 7	CG p2. s3. a2. 2010	. . +I NF 1. 2410E+7	3 0 1 4	CG p3. s4. a2. 2030	. . +I NF 1. 4252E+7
2 9 6 8	CG p2. s3. a2. 2020	. 0. 600 +I NF .	3 0 1 5	CG p3. s4. a3. 2010	. . +I NF 4. 5399E+7
2 9 6 9	CG p2. s3. a2. 2030	. 0. 086 +I NF .	3 0 1 6	CG p3. s4. a3. 2020	. . +I NF 2. 1029E+7
2 9 7 0	CG p2. s3. a3. 2010	. . +I NF 1. 2410E+7	3 0 1 7	CG p3. s4. a3. 2030	. . +I NF 1. 4252E+7
2 9 7 1	CG p2. s3. a3. 2020	. 0. 542 +I NF .	3 0 1 8	TG p1. s1. a1. 2010	. . +I NF 1. 3150E+8
2 9 7 2	CG p2. s3. a3. 2030	. 0. 022 +I NF .	3 0 1 9	TG p1. s1. a1. 2020	. . +I NF 6. 0909E+7
2 9 7 3	CG p2. s4. a1. 2010	. 5. 817 +I NF .	3 0 2 0	TG p1. s1. a1. 2030	. . +I NF 4. 1280E+7
2 9 7 4	CG p2. s4. a1. 2020	. 9. 492 +I NF .	3 0 2 1	TG p1. s1. a2. 2010	. . +I NF 1. 8090E+7
2 9 7 5	CG p2. s4. a1. 2030	. 9. 492 +I NF .	3 0 2 2	TG p1. s1. a2. 2020	. . +I NF 7. 6136E+6
2 9 7 6	CG p2. s4. a2. 2010	. 5. 817 +I NF .	3 0 2 3	TG p1. s1. a2. 2030	. . +I NF 5. 6788E+6
2 9 7 7	CG p2. s4. a2. 2020	. 9. 492 +I NF .	3 0 2 4	TG p1. s1. a3. 2010	. 1. 440 +I NF .
2 9 7 8	CG p2. s4. a2. 2030	. 9. 492 +I NF .	3 0 2 5	TG p1. s1. a3. 2020	. 1. 440 +I NF .
2 9 7 9	CG p2. s4. a3. 2010	. 5. 817 +I NF .	3 0 2 6	TG p1. s1. a3. 2030	. 1. 440 +I NF .
2 9 8 0	CG p2. s4. a3. 2020	. 9. 492 +I NF .	3 0 2 7	TG p1. s2. a1. 2010	. 1. 440 +I NF .
2 9 8 1	CG p2. s4. a3. 2030	. 9. 492 +I NF .	3 0 2 8	TG p1. s2. a1. 2020	. 1. 440 +I NF .
2 9 8 2	CG p3. s1. a1. 2010	. . +I NF 2. 5360E+8	3 0 2 9	TG p1. s2. a1. 2030	. 1. 440 +I NF .
2 9 8 3	CG p3. s1. a1. 2020	. . +I NF 2. 5550E+7	3 0 3 0	TG p1. s2. a2. 2010	. 1. 440 +I NF .
2 9 8 4	CG p3. s1. a1. 2030	. . +I NF 7. 8669E+7	3 0 3 1	TG p1. s2. a2. 2020	. 1. 440 +I NF .
2 9 8 5	CG p3. s1. a2. 2010	. . +I NF 3. 1700E+7	3 0 3 2	TG p1. s2. a2. 2030	. 1. 440 +I NF .
2 9 8 6	CG p3. s1. a2. 2020	. . +I NF 3. 1937E+6	3 0 3 3	TG p1. s2. a3. 2010	. 1. 440 +I NF .
2 9 8 7	CG p3. s1. a2. 2030	. . +I NF 9. 9515E+6	3 0 3 4	TG p1. s2. a3. 2020	. 1. 440 +I NF .
2 9 8 8	CG p3. s1. a3. 2010	. . +I NF 3. 1700E+7	3 0 3 5	TG p1. s2. a3. 2030	. 1. 440 +I NF .
2 9 8 9	CG p3. s1. a3. 2020	. . +I NF 3. 1937E+6	3 0 3 6	TG p1. s3. a1. 2010	. 1. 280 +I NF .
2 9 9 0	CG p3. s1. a3. 2030	. . +I NF 9. 9515E+6	3 0 3 7	TG p1. s3. a1. 2020	. 1. 280 +I NF .
2 9 9 1	CG p3. s2. a1. 2010	. . +I NF 1. 7550E+8	3 0 3 8	TG p1. s3. a1. 2030	. 1. 280 +I NF .
2 9 9 2	CG p3. s2. a1. 2020	. . +I NF 8. 1288E+7	3 0 3 9	TG p1. s3. a2. 2010	. 1. 280 +I NF .
2 9 9 3	CG p3. s2. a1. 2030	. . +I NF 5. 5092E+7	3 0 4 0	TG p1. s3. a2. 2020	. 1. 280 +I NF .
2 9 9 4	CG p3. s2. a2. 2010	. . +I NF 2. 1937E+7	3 0 4 1	TG p1. s3. a2. 2030	. 1. 280 +I NF .
2 9 9 5	CG p3. s2. a2. 2020	. . +I NF 1. 0161E+7	3 0 4 2	TG p1. s3. a3. 2010	. 1. 280 +I NF .
2 9 9 6	CG p3. s2. a2. 2030	. . +I NF 6. 8866E+6	3 0 4 3	TG p1. s3. a3. 2020	. 1. 280 +I NF .
2 9 9 7	CG p3. s2. a3. 2010	. . +I NF 2. 1937E+7	3 0 4 4	TG p1. s3. a3. 2030	. 1. 280 +I NF .
2 9 9 8	CG p3. s2. a3. 2020	. . +I NF 1. 0161E+7	3 0 4 5	TG p1. s4. a1. 2010	. 1. 280 +I NF .
2 9 9 9	CG p3. s2. a3. 2030	. . +I NF 6. 8866E+6	3 0 4 6	TG p1. s4. a1. 2020	. 1. 280 +I NF .
3 0 0 0	CG p3. s3. a1. 2010	. . +I NF 9. 4393E+7	3 0 4 7	TG p1. s4. a1. 2030	. 1. 280 +I NF .
3 0 0 1	CG p3. s3. a1. 2020	. . +I NF 4. 3722E+7	3 0 4 8	TG p1. s4. a2. 2010	. 1. 280 +I NF .
3 0 0 2	CG p3. s3. a1. 2030	. . +I NF 2. 9632E+7	3 0 4 9	TG p1. s4. a2. 2020	. 1. 280 +I NF .
3 0 0 3	CG p3. s3. a2. 2010	. . +I NF 1. 1799E+7	3 0 5 0	TG p1. s4. a2. 2030	. 1. 280 +I NF .
3 0 0 4	CG p3. s3. a2. 2020	. . +I NF 5. 4653E+6	3 0 5 1	TG p1. s4. a3. 2010	. 1. 280 +I NF .
3 0 0 5	CG p3. s3. a2. 2030	. . +I NF 3. 7040E+6	3 0 5 2	TG p1. s4. a3. 2020	. 1. 280 +I NF .
3 0 0 6	CG p3. s3. a3. 2010	. . +I NF 1. 1799E+7	3 0 5 3	TG p1. s4. a3. 2030	. 1. 280 +I NF .
3 0 0 7	CG p3. s3. a3. 2020	. . +I NF 5. 4653E+6	3 0 5 4	TG p2. s1. a1. 2010	. . +I NF 5. 0680E+8
3 0 0 8	CG p3. s3. a3. 2030	. . +I NF 3. 7040E+6	3 0 5 5	TG p2. s1. a1. 2020	. . +I NF 2. 1330E+8
3 0 0 9	CG p3. s4. a1. 2010	. . +I NF 3. 6320E+8	3 0 5 6	TG p2. s1. a1. 2030	. . +I NF 1. 4456E+8
3 0 1 0	CG p3. s4. a1. 2020	. . +I NF 1. 6823E+8	3 0 5 7	TG p2. s1. a2. 2010	. . +I NF 6. 3350E+7

3 0 5 8	TG p2. s1. a2. 2020	. .	+I NF 2. 6663E+7	3 1 0 5	TG p3. s2. a3. 2010	. .	+I NF 6. 9400E+7
3 0 5 9	TG p2. s1. a2. 2030	. .	+I NF 1. 9887E+7	3 1 0 6	TG p3. s2. a3. 2020	. .	+I NF 3. 2146E+7
3 0 6 0	TG p2. s1. a3. 2010	. .	+I NF 6. 3350E+7	3 1 0 7	TG p3. s2. a3. 2030	. .	+I NF 2. 1786E+7
3 0 6 1	TG p2. s1. a3. 2020	. .	+I NF 2. 6663E+7	3 1 0 8	TG p3. s3. a1. 2010	. .	+I NF 1. 0334E+9
3 0 6 2	TG p2. s1. a3. 2030	. .	+I NF 1. 8071E+7	3 1 0 9	TG p3. s3. a1. 2020	. .	+I NF 4. 7865E+8
3 0 6 3	TG p2. s2. a1. 2010	. .	+I NF 4. 3299E+8	3 1 1 0	TG p3. s3. a1. 2030	. .	+I NF 3. 2440E+8
3 0 6 4	TG p2. s2. a1. 2020	. .	+I NF 2. 0056E+8	3 1 1 1	TG p3. s3. a2. 2010	. .	+I NF 1. 2917E+8
3 0 6 5	TG p2. s2. a1. 2030	. .	+I NF 1. 3593E+8	3 1 1 2	TG p3. s3. a2. 2020	. .	+I NF 5. 9831E+7
3 0 6 6	TG p2. s2. a2. 2010	. .	+I NF 5. 4124E+7	3 1 1 3	TG p3. s3. a2. 2030	. .	+I NF 4. 0550E+7
3 0 6 7	TG p2. s2. a2. 2020	. .	+I NF 2. 5070E+7	3 1 1 4	TG p3. s3. a3. 2010	. .	+I NF 1. 2917E+8
3 0 6 8	TG p2. s2. a2. 2030	. .	+I NF 1. 6991E+7	3 1 1 5	TG p3. s3. a3. 2020	. .	+I NF 5. 9831E+7
3 0 6 9	TG p2. s2. a3. 2010	. .	+I NF 5. 4124E+7	3 1 1 6	TG p3. s3. a3. 2030	. .	+I NF 4. 0550E+7
3 0 7 0	TG p2. s2. a3. 2020	. .	+I NF 2. 5070E+7	3 1 1 7	TG p3. s4. a1. 2010	. .	+I NF 1. 1490E+9
3 0 7 1	TG p2. s2. a3. 2030	. .	+I NF 1. 6991E+7	3 1 1 8	TG p3. s4. a1. 2020	. .	+I NF 5. 3222E+8
3 0 7 2	TG p2. s3. a1. 2010	. .	+I NF 1. 0868E+9	3 1 1 9	TG p3. s4. a1. 2030	. .	+I NF 3. 6070E+8
3 0 7 3	TG p2. s3. a1. 2020	. .	+I NF 4. 5743E+8	3 1 2 0	TG p3. s4. a2. 2010	. .	+I NF 1. 4363E+8
3 0 7 4	TG p2. s3. a1. 2030	. .	+I NF 3. 1002E+8	3 1 2 1	TG p3. s4. a2. 2020	. .	+I NF 6. 6527E+7
3 0 7 5	TG p2. s3. a2. 2010	. .	+I NF 1. 3585E+8	3 1 2 2	TG p3. s4. a2. 2030	. .	+I NF 4. 5088E+7
3 0 7 6	TG p2. s3. a2. 2020	. .	+I NF 5. 7179E+7	3 1 2 3	TG p3. s4. a3. 2010	. .	+I NF 1. 4363E+8
3 0 7 7	TG p2. s3. a2. 2030	. .	+I NF 3. 8752E+7	3 1 2 4	TG p3. s4. a3. 2020	. .	+I NF 6. 6527E+7
3 0 7 8	TG p2. s3. a3. 2010	. .	+I NF 1. 3585E+8	3 1 2 5	TG p3. s4. a3. 2030	. .	+I NF 4. 5088E+7
3 0 7 9	TG p2. s3. a3. 2020	. .	+I NF 5. 7179E+7	3 1 2 6	WP. p1. s1. a1. 2010	. .	0. 680 +I NF .
3 0 8 0	TG p2. s3. a3. 2030	. .	+I NF 3. 8752E+7	3 1 2 7	WP. p1. s1. a1. 2020	. .	0. 680 +I NF .
3 0 8 1	TG p2. s4. a1. 2010	. .	1. 280 +I NF .	3 1 2 8	WP. p1. s1. a1. 2030	. .	0. 680 +I NF .
3 0 8 2	TG p2. s4. a1. 2020	. .	1. 280 +I NF .	3 1 2 9	WP. p1. s1. a2. 2010	. .	0. 680 +I NF .
3 0 8 3	TG p2. s4. a1. 2030	. .	1. 280 +I NF .	3 1 3 0	WP. p1. s1. a2. 2020	. .	0. 680 +I NF .
3 0 8 4	TG p2. s4. a2. 2010	. .	1. 280 +I NF .	3 1 3 1	WP. p1. s1. a2. 2030	. .	0. 680 +I NF .
3 0 8 5	TG p2. s4. a2. 2020	. .	1. 280 +I NF .	3 1 3 2	WP. p1. s1. a3. 2010	. .	0. 680 +I NF .
3 0 8 6	TG p2. s4. a2. 2030	. .	1. 280 +I NF .	3 1 3 3	WP. p1. s1. a3. 2020	. .	0. 680 +I NF .
3 0 8 7	TG p2. s4. a3. 2010	. .	1. 280 +I NF .	3 1 3 4	WP. p1. s1. a3. 2030	. .	0. 680 +I NF .
3 0 8 8	TG p2. s4. a3. 2020	. .	1. 280 +I NF .	3 1 3 5	WP. p1. s2. a1. 2010	. .	0. 680 +I NF .
3 0 8 9	TG p2. s4. a3. 2030	. .	1. 280 +I NF .	3 1 3 6	WP. p1. s2. a1. 2020	. .	0. 680 +I NF .
3 0 9 0	TG p3. s1. a1. 2010	. .	+I NF 8. 0230E+8	3 1 3 7	WP. p1. s2. a1. 2030	. .	0. 680 +I NF .
3 0 9 1	TG p3. s1. a1. 2020	. .	+I NF 2. 7970E+8	3 1 3 8	WP. p1. s2. a2. 2010	. .	0. 680 +I NF .
3 0 9 2	TG p3. s1. a1. 2030	. .	+I NF 2. 5092E+8	3 1 3 9	WP. p1. s2. a2. 2020	. .	0. 680 +I NF .
3 0 9 3	TG p3. s1. a2. 2010	. .	+I NF 1. 0029E+8	3 1 4 0	WP. p1. s2. a2. 2030	. .	0. 680 +I NF .
3 0 9 4	TG p3. s1. a2. 2020	. .	+I NF 3. 4963E+7	3 1 4 1	WP. p1. s2. a3. 2010	. .	0. 680 +I NF .
3 0 9 5	TG p3. s1. a2. 2030	. .	+I NF 3. 1483E+7	3 1 4 2	WP. p1. s2. a3. 2020	. .	0. 680 +I NF .
3 0 9 6	TG p3. s1. a3. 2010	. .	+I NF 1. 0029E+8	3 1 4 3	WP. p1. s2. a3. 2030	. .	0. 680 +I NF .
3 0 9 7	TG p3. s1. a3. 2020	. .	+I NF 3. 4963E+7	3 1 4 4	WP. p1. s3. a1. 2010	. .	0. 680 +I NF .
3 0 9 8	TG p3. s1. a3. 2030	. .	+I NF 3. 1483E+7	3 1 4 5	WP. p1. s3. a1. 2020	. .	0. 680 +I NF .
3 0 9 9	TG p3. s2. a1. 2010	. .	+I NF 5. 5520E+8	3 1 4 6	WP. p1. s3. a1. 2030	. .	0. 680 +I NF .
3 1 0 0	TG p3. s2. a1. 2020	. .	+I NF 2. 5717E+8	3 1 4 7	WP. p1. s3. a2. 2010	. .	0. 680 +I NF .
3 1 0 1	TG p3. s2. a1. 2030	. .	+I NF 1. 7429E+8	3 1 4 8	WP. p1. s3. a2. 2020	. .	0. 680 +I NF .
3 1 0 2	TG p3. s2. a2. 2010	. .	+I NF 6. 9400E+7	3 1 4 9	WP. p1. s3. a2. 2030	. .	0. 680 +I NF .
3 1 0 3	TG p3. s2. a2. 2020	. .	+I NF 3. 2146E+7	3 1 5 0	WP. p1. s3. a3. 2010	. .	0. 680 +I NF .
3 1 0 4	TG p3. s2. a2. 2030	. .	+I NF 2. 1786E+7	3 1 5 1	WP. p1. s3. a3. 2020	. .	0. 680 +I NF .

3 1 5 2 WP. p1. s3. a3. 2030 . 0. 680 +I NF .  
 3 1 5 3 WP. p1. s4. a1. 2010 . 0. 680 +I NF .  
 3 1 5 4 WP. p1. s4. a1. 2020 . 0. 680 +I NF .  
 3 1 5 5 WP. p1. s4. a1. 2030 . 0. 680 +I NF .  
 3 1 5 6 WP. p1. s4. a2. 2010 . 0. 680 +I NF .  
 3 1 5 7 WP. p1. s4. a2. 2020 . 0. 680 +I NF .  
 3 1 5 8 WP. p1. s4. a2. 2030 . 0. 680 +I NF .  
 3 1 5 9 WP. p1. s4. a3. 2010 . 0. 680 +I NF .  
 3 1 6 0 WP. p1. s4. a3. 2020 . 0. 680 +I NF .  
 3 1 6 1 WP. p1. s4. a3. 2030 . 0. 680 +I NF .  
 3 1 6 2 WP. p2. s1. a1. 2010 . 0. 680 +I NF .  
 3 1 6 3 WP. p2. s1. a1. 2020 . 0. 680 +I NF .  
 3 1 6 4 WP. p2. s1. a1. 2030 . 0. 680 +I NF .  
 3 1 6 5 WP. p2. s1. a2. 2010 . 0. 680 +I NF .  
 3 1 6 6 WP. p2. s1. a2. 2020 . 0. 680 +I NF .  
 3 1 6 7 WP. p2. s1. a2. 2030 . 0. 680 +I NF .  
 3 1 6 8 WP. p2. s1. a3. 2010 . 0. 680 +I NF .  
 3 1 6 9 WP. p2. s1. a3. 2020 . 0. 680 +I NF .  
 3 1 7 0 WP. p2. s1. a3. 2030 . 0. 680 +I NF .  
 3 1 7 1 WP. p2. s2. a1. 2010 . 0. 680 +I NF .  
 3 1 7 2 WP. p2. s2. a1. 2020 . 0. 680 +I NF .  
 3 1 7 3 WP. p2. s2. a1. 2030 . 0. 680 +I NF .  
 3 1 7 4 WP. p2. s2. a2. 2010 . 0. 680 +I NF .  
 3 1 7 5 WP. p2. s2. a2. 2020 . 0. 680 +I NF .  
 3 1 7 6 WP. p2. s2. a2. 2030 . 0. 680 +I NF .  
 3 1 7 7 WP. p2. s2. a3. 2010 . 0. 680 +I NF .  
 3 1 7 8 WP. p2. s2. a3. 2020 . 0. 680 +I NF .  
 3 1 7 9 WP. p2. s2. a3. 2030 . 0. 680 +I NF .  
 3 1 8 0 WP. p2. s3. a1. 2010 . 0. 680 +I NF .  
 3 1 8 1 WP. p2. s3. a1. 2020 . 0. 680 +I NF .  
 3 1 8 2 WP. p2. s3. a1. 2030 . 0. 680 +I NF .  
 3 1 8 3 WP. p2. s3. a2. 2010 . 0. 680 +I NF .  
 3 1 8 4 WP. p2. s3. a2. 2020 . 0. 680 +I NF .  
 3 1 8 5 WP. p2. s3. a2. 2030 . 0. 680 +I NF .  
 3 1 8 6 WP. p2. s3. a3. 2010 . 0. 680 +I NF .  
 3 1 8 7 WP. p2. s3. a3. 2020 . 0. 680 +I NF .  
 3 1 8 8 WP. p2. s3. a3. 2030 . 0. 680 +I NF .  
 3 1 8 9 WP. p2. s4. a1. 2010 . 0. 680 +I NF .  
 3 1 9 0 WP. p2. s4. a1. 2020 . 0. 680 +I NF .  
 3 1 9 1 WP. p2. s4. a1. 2030 . 0. 680 +I NF .  
 3 1 9 2 WP. p2. s4. a2. 2010 . 0. 680 +I NF .  
 3 1 9 3 WP. p2. s4. a2. 2020 . 0. 680 +I NF .  
 3 1 9 4 WP. p2. s4. a2. 2030 . 0. 680 +I NF .  
 3 1 9 5 WP. p2. s4. a3. 2010 . 0. 680 +I NF .  
 3 1 9 6 WP. p2. s4. a3. 2020 . 0. 680 +I NF .  
 3 1 9 7 WP. p2. s4. a3. 2030 . 0. 680 +I NF .  
 3 1 9 8 WP. p3. s1. a1. 2010 . 0. 680 +I NF .

3 1 9 9 WP. p3. s1. a1. 2020 . 0. 680 +I NF .  
 3 2 0 0 WP. p3. s1. a1. 2030 . 0. 680 +I NF .  
 3 2 0 1 WP. p3. s1. a2. 2010 . 0. 680 +I NF .  
 3 2 0 2 WP. p3. s1. a2. 2020 . 0. 680 +I NF .  
 3 2 0 3 WP. p3. s1. a2. 2030 . 0. 680 +I NF .  
 3 2 0 4 WP. p3. s1. a3. 2010 . 0. 680 +I NF .  
 3 2 0 5 WP. p3. s1. a3. 2020 . 0. 680 +I NF .  
 3 2 0 6 WP. p3. s1. a3. 2030 . 0. 680 +I NF .  
 3 2 0 7 WP. p3. s2. a1. 2010 . 0. 680 +I NF .  
 3 2 0 8 WP. p3. s2. a1. 2020 . 0. 680 +I NF .  
 3 2 0 9 WP. p3. s2. a1. 2030 . 0. 680 +I NF .  
 3 2 1 0 WP. p3. s2. a2. 2010 . 0. 680 +I NF .  
 3 2 1 1 WP. p3. s2. a2. 2020 . 0. 680 +I NF .  
 3 2 1 2 WP. p3. s2. a2. 2030 . 0. 680 +I NF .  
 3 2 1 3 WP. p3. s2. a3. 2010 . 0. 680 +I NF .  
 3 2 1 4 WP. p3. s2. a3. 2020 . 0. 680 +I NF .  
 3 2 1 5 WP. p3. s2. a3. 2030 . 0. 680 +I NF .  
 3 2 1 6 WP. p3. s3. a1. 2010 . 0. 680 +I NF .  
 3 2 1 7 WP. p3. s3. a1. 2020 . 0. 680 +I NF .  
 3 2 1 8 WP. p3. s3. a1. 2030 . 0. 680 +I NF .  
 3 2 1 9 WP. p3. s3. a2. 2010 . 0. 680 +I NF .  
 3 2 2 0 WP. p3. s3. a2. 2020 . 0. 680 +I NF .  
 3 2 2 1 WP. p3. s3. a2. 2030 . 0. 680 +I NF .  
 3 2 2 2 WP. p3. s3. a3. 2010 . 0. 680 +I NF .  
 3 2 2 3 WP. p3. s3. a3. 2020 . 0. 680 +I NF .  
 3 2 2 4 WP. p3. s3. a3. 2030 . 0. 680 +I NF .  
 3 2 2 5 WP. p3. s4. a1. 2010 . 0. 680 +I NF .  
 3 2 2 6 WP. p3. s4. a1. 2020 . 0. 680 +I NF .  
 3 2 2 7 WP. p3. s4. a1. 2030 . 0. 680 +I NF .  
 3 2 2 8 WP. p3. s4. a2. 2010 . 0. 680 +I NF .  
 3 2 2 9 WP. p3. s4. a2. 2020 . 0. 680 +I NF .  
 3 2 3 0 WP. p3. s4. a2. 2030 . 0. 680 +I NF .  
 3 2 3 1 WP. p3. s4. a3. 2010 . 0. 680 +I NF .  
 3 2 3 2 WP. p3. s4. a3. 2020 . 0. 680 +I NF .  
 3 2 3 3 WP. p3. s4. a3. 2030 . 0. 680 +I NF .  
 3 2 3 4

**3 2 3 5 ---- VAR I nv I nvest ment**

**(I nvest ment s)**

3 2 3 6  
 3 2 3 7 LOWER LEVEL UPPER MARGI NAL  
 3 2 3 8  
 3 2 3 9 NC. 2010 . . +I NF 4. 1974E+8  
 3 2 4 0 NC. 2020 . 3. 820 +I NF .  
 3 2 4 1 NC. 2030 . 8. 684 +I NF .  
 3 2 4 2 TH. 2010 . . +I NF 4. 3096E+8  
 3 2 4 3 TH. 2020 . . +I NF 1. 0375E+8  
 3 2 4 4 TH. 2030 . . +I NF 6. 4111E+7

3 2 4 5 CG 2010 . 0.572 +I NF .  
 3 2 4 6 CG 2020 . 4.594 +I NF .  
 3 2 4 7 CG 2030 . . +I NF 4.1120E+7  
 3 2 4 8 TG 2010 . . +I NF 1.4121E+7  
 3 2 4 9 TG 2020 . . +I NF 6.5805E+6  
 3 2 5 0 TG 2030 . . +I NF 4.4208E+7  
 3 2 5 1 WP. 2010 . . +I NF 1.8969E+9  
 3 2 5 2 WP. 2020 . . +I NF 7.1982E+8  
 3 2 5 3 WP. 2030 . . +I NF 2.2373E+8  
 3 2 5 4

**3 2 5 5 ----- VAR CAPAVAI BLE**

**( Available Capacities )**

3 2 5 6  
 3 2 5 7 LOWER LEVEL UPPER MARGI NAL  
 3 2 5 8  
 3 2 5 9 NC. s1. 2010 . 53.720 +I NF .  
 3 2 6 0 NC. s1. 2020 . 56.967 +I NF .  
 3 2 6 1 NC. s1. 2030 . 64.348 +I NF .  
 3 2 6 2 NC. s2. 2010 . 53.720 +I NF .  
 3 2 6 3 NC. s2. 2020 . 56.967 +I NF .  
 3 2 6 4 NC. s2. 2030 . 64.348 +I NF .  
 3 2 6 5 NC. s3. 2010 . 37.920 +I NF .  
 3 2 6 6 NC. s3. 2020 . 40.212 +I NF .  
 3 2 6 7 NC. s3. 2030 . 45.422 +I NF .  
 3 2 6 8 NC. s4. 2010 . 37.920 +I NF .  
 3 2 6 9 NC. s4. 2020 . 40.212 +I NF .  
 3 2 7 0 NC. s4. 2030 . 45.422 +I NF .  
 3 2 7 1 TH. s1. 2010 . 11.430 +I NF .  
 3 2 7 2 TH. s1. 2020 . 11.430 +I NF .  
 3 2 7 3 TH. s1. 2030 . 11.430 +I NF .  
 3 2 7 4 TH. s2. 2010 . 11.430 +I NF .  
 3 2 7 5 TH. s2. 2020 . 11.430 +I NF .  
 3 2 7 6 TH. s2. 2030 . 11.430 +I NF .  
 3 2 7 7 TH. s3. 2010 . 10.160 +I NF .  
 3 2 7 8 TH. s3. 2020 . 10.160 +I NF .  
 3 2 7 9 TH. s3. 2030 . 10.160 +I NF .  
 3 2 8 0 TH. s4. 2010 . 10.160 +I NF .  
 3 2 8 1 TH. s4. 2020 . 10.160 +I NF .  
 3 2 8 2 TH. s4. 2030 . 10.160 +I NF .  
 3 2 8 3 CG s1. 2010 . 6.544 +I NF .  
 3 2 8 4 CG s1. 2020 . 10.679 +I NF .  
 3 2 8 5 CG s1. 2030 . 10.679 +I NF .  
 3 2 8 6 CG s2. 2010 . 6.544 +I NF .  
 3 2 8 7 CG s2. 2020 . 10.679 +I NF .  
 3 2 8 8 CG s2. 2030 . 10.679 +I NF .  
 3 2 8 9 CG s3. 2010 . 5.817 +I NF .  
 3 2 9 0 CG s3. 2020 . 9.492 +I NF .

3 2 9 1 CG s3. 2030 . 9.492 +I NF .  
 3 2 9 2 CG s4. 2010 . 5.817 +I NF .  
 3 2 9 3 CG s4. 2020 . 9.492 +I NF .  
 3 2 9 4 CG s4. 2030 . 9.492 +I NF .  
 3 2 9 5 TG s1. 2010 . 1.440 +I NF .  
 3 2 9 6 TG s1. 2020 . 1.440 +I NF .  
 3 2 9 7 TG s1. 2030 . 1.440 +I NF .  
 3 2 9 8 TG s2. 2010 . 1.440 +I NF .  
 3 2 9 9 TG s2. 2020 . 1.440 +I NF .  
 3 3 0 0 TG s2. 2030 . 1.440 +I NF .  
 3 3 0 1 TG s3. 2010 . 1.280 +I NF .  
 3 3 0 2 TG s3. 2020 . 1.280 +I NF .  
 3 3 0 3 TG s3. 2030 . 1.280 +I NF .  
 3 3 0 4 TG s4. 2010 . 1.280 +I NF .  
 3 3 0 5 TG s4. 2020 . 1.280 +I NF .  
 3 3 0 6 TG s4. 2030 . 1.280 +I NF .  
 3 3 0 7 WP. s1. 2010 . 0.680 +I NF .  
 3 3 0 8 WP. s1. 2020 . 0.680 +I NF .  
 3 3 0 9 WP. s1. 2030 . 0.680 +I NF .  
 3 3 1 0 WP. s2. 2010 . 0.680 +I NF .  
 3 3 1 1 WP. s2. 2020 . 0.680 +I NF .  
 3 3 1 2 WP. s2. 2030 . 0.680 +I NF .  
 3 3 1 3 WP. s3. 2010 . 0.680 +I NF .  
 3 3 1 4 WP. s3. 2020 . 0.680 +I NF .  
 3 3 1 5 WP. s3. 2030 . 0.680 +I NF .  
 3 3 1 6 WP. s4. 2010 . 0.680 +I NF .  
 3 3 1 7 WP. s4. 2020 . 0.680 +I NF .  
 3 3 1 8 WP. s4. 2030 . 0.680 +I NF .  
 3 3 1 9

**3 3 2 0 ----- VAR capel ec**

**( Capacities )**

3 3 2 1  
 3 3 2 2 LOWER LEVEL UPPER MARGI NAL  
 3 3 2 3  
 3 3 2 4 NC. 2010 . 63.200 +I NF .  
 3 3 2 5 NC. 2020 . 67.020 +I NF .  
 3 3 2 6 NC. 2030 . 75.704 +I NF .  
 3 3 2 7 TH. 2010 . 12.700 +I NF .  
 3 3 2 8 TH. 2020 . 12.700 +I NF .  
 3 3 2 9 TH. 2030 . 12.700 +I NF .  
 3 3 3 0 CG 2010 . 7.272 +I NF .  
 3 3 3 1 CG 2020 . 11.865 +I NF .  
 3 3 3 2 CG 2030 . 11.865 +I NF .  
 3 3 3 3 TG 2010 . 1.600 +I NF .  
 3 3 3 4 TG 2020 . 1.600 +I NF .  
 3 3 3 5 TG 2030 . 1.600 +I NF .  
 3 3 3 6 WP. 2010 . 3.400 +I NF .

3 3 3 7 WP. 2020 . 3. 400 +I NF .  
 3 3 3 8 WP. 2030 . 3. 400 +I NF .  
 3 3 3 9  
**3 3 4 0 ---- VAR emis**  
**(CO2 Emissions)**  
 3 3 4 1  
 3 3 4 2 LOWER LEVEL UPPER MARGINAL  
 3 3 4 3  
 3 3 4 4 TH. p1. s1. a1. 2010 . 2. 2114E+6 +I NF .  
 3 3 4 5 TH. p1. s1. a1. 2020 . 2. 2114E+6 +I NF .  
 3 3 4 6 TH. p1. s1. a1. 2030 . 2. 2114E+6 +I NF .  
 3 3 4 7 TH. p1. s1. a2. 2010 . 1. 6280E+6 +I NF .  
 3 3 4 8 TH. p1. s1. a2. 2020 . 2. 2114E+6 +I NF .  
 3 3 4 9 TH. p1. s1. a2. 2030 . 2. 0022E+6 +I NF .  
 3 3 5 0 TH. p1. s1. a3. 2010 . 2. 2114E+6 +I NF .  
 3 3 5 1 TH. p1. s1. a3. 2020 . 2. 2114E+6 +I NF .  
 3 3 5 2 TH. p1. s1. a3. 2030 . 2. 2114E+6 +I NF .  
 3 3 5 3 TH. p1. s2. a1. 2010 . . +I NF 53. 680  
 3 3 5 4 TH. p1. s2. a1. 2020 . . +I NF 24. 864  
 3 3 5 5 TH. p1. s2. a1. 2030 . . +I NF 16. 851  
 3 3 5 6 TH. p1. s2. a2. 2010 . . +I NF 6. 710  
 3 3 5 7 TH. p1. s2. a2. 2020 . . +I NF 3. 108  
 3 3 5 8 TH. p1. s2. a2. 2030 . . +I NF 2. 106  
 3 3 5 9 TH. p1. s2. a3. 2010 . . +I NF 6. 710  
 3 3 6 0 TH. p1. s2. a3. 2020 . . +I NF 3. 108  
 3 3 6 1 TH. p1. s2. a3. 2030 . . +I NF 2. 106  
 3 3 6 2 TH. p1. s3. a1. 2010 . . +I NF 53. 680  
 3 3 6 3 TH. p1. s3. a1. 2020 . . +I NF 24. 864  
 3 3 6 4 TH. p1. s3. a1. 2030 . . +I NF 16. 851  
 3 3 6 5 TH. p1. s3. a2. 2010 . . +I NF 6. 710  
 3 3 6 6 TH. p1. s3. a2. 2020 . . +I NF 3. 108  
 3 3 6 7 TH. p1. s3. a2. 2030 . . +I NF 2. 106  
 3 3 6 8 TH. p1. s3. a3. 2010 . . +I NF 6. 710  
 3 3 6 9 TH. p1. s3. a3. 2020 . . +I NF 3. 108  
 3 3 7 0 TH. p1. s3. a3. 2030 . . +I NF 2. 106  
 3 3 7 1 TH. p1. s4. a1. 2010 . . +I NF 53. 680  
 3 3 7 2 TH. p1. s4. a1. 2020 . . +I NF 24. 864  
 3 3 7 3 TH. p1. s4. a1. 2030 . . +I NF 16. 851  
 3 3 7 4 TH. p1. s4. a2. 2010 . . +I NF 6. 710  
 3 3 7 5 TH. p1. s4. a2. 2020 . . +I NF 3. 108  
 3 3 7 6 TH. p1. s4. a2. 2030 . . +I NF 2. 106  
 3 3 7 7 TH. p1. s4. a3. 2010 . . +I NF 6. 710  
 3 3 7 8 TH. p1. s4. a3. 2020 . . +I NF 3. 108  
 3 3 7 9 TH. p1. s4. a3. 2030 . . +I NF 2. 106  
 3 3 8 0 TH. p2. s1. a1. 2010 . 6. 7088E+6 +I NF .  
 3 3 8 1 TH. p2. s1. a1. 2020 . 7. 7443E+6 +I NF .  
 3 3 8 2 TH. p2. s1. a1. 2030 . 7. 7443E+6 +I NF .  
 3 3 8 3 TH. p2. s1. a2. 2010 . 5. 7011E+6 +I NF .  
 3 3 8 4 TH. p2. s1. a2. 2020 . 7. 7443E+6 +I NF .  
 3 3 8 5 TH. p2. s1. a2. 2030 . 7. 0118E+6 +I NF .  
 3 3 8 6 TH. p2. s1. a3. 2010 . 7. 5197E+6 +I NF .  
 3 3 8 7 TH. p2. s1. a3. 2020 . 7. 7443E+6 +I NF .  
 3 3 8 8 TH. p2. s1. a3. 2030 . 7. 7443E+6 +I NF .  
 3 3 8 9 TH. p2. s2. a1. 2010 . 2. 3289E+6 +I NF .  
 3 3 9 0 TH. p2. s2. a1. 2020 . 3. 8312E+6 +I NF .  
 3 3 9 1 TH. p2. s2. a1. 2030 . 2. 9403E+6 +I NF .  
 3 3 9 2 TH. p2. s2. a2. 2010 . 1. 8246E+6 +I NF .  
 3 3 9 3 TH. p2. s2. a2. 2020 . 3. 2765E+6 +I NF .  
 3 3 9 4 TH. p2. s2. a2. 2030 . 2. 3351E+6 +I NF .  
 3 3 9 5 TH. p2. s2. a3. 2010 . 2. 2932E+6 +I NF .  
 3 3 9 6 TH. p2. s2. a3. 2020 . 3. 7920E+6 +I NF .  
 3 3 9 7 TH. p2. s2. a3. 2030 . 2. 8975E+6 +I NF .  
 3 3 9 8 TH. p2. s3. a1. 2010 . 1. 2462E+7 +I NF .  
 3 3 9 9 TH. p2. s3. a1. 2020 . 1. 4762E+7 +I NF .  
 3 4 0 0 TH. p2. s3. a1. 2030 . 1. 4762E+7 +I NF .  
 3 4 0 1 TH. p2. s3. a2. 2010 . 1. 2142E+7 +I NF .  
 3 4 0 2 TH. p2. s3. a2. 2020 . 1. 4762E+7 +I NF .  
 3 4 0 3 TH. p2. s3. a2. 2030 . 1. 4762E+7 +I NF .  
 3 4 0 4 TH. p2. s3. a3. 2010 . 1. 2066E+7 +I NF .  
 3 4 0 5 TH. p2. s3. a3. 2020 . 1. 4762E+7 +I NF .  
 3 4 0 6 TH. p2. s3. a3. 2030 . 1. 4762E+7 +I NF .  
 3 4 0 7 TH. p2. s4. a1. 2010 . . +I NF 53. 680  
 3 4 0 8 TH. p2. s4. a1. 2020 . . +I NF 24. 864  
 3 4 0 9 TH. p2. s4. a1. 2030 . . +I NF 16. 851  
 3 4 1 0 TH. p2. s4. a2. 2010 . . +I NF 6. 710  
 3 4 1 1 TH. p2. s4. a2. 2020 . . +I NF 3. 108  
 3 4 1 2 TH. p2. s4. a2. 2030 . . +I NF 2. 106  
 3 4 1 3 TH. p2. s4. a3. 2010 . . +I NF 6. 710  
 3 4 1 4 TH. p2. s4. a3. 2020 . . +I NF 3. 108  
 3 4 1 5 TH. p2. s4. a3. 2030 . . +I NF 2. 106  
 3 4 1 6 TH. p3. s1. a1. 2010 . . +I NF .  
 3 4 1 7 TH. p3. s1. a1. 2020 . 1. 5843E+6 +I NF .  
 3 4 1 8 TH. p3. s1. a1. 2030 . . +I NF .  
 3 4 1 9 TH. p3. s1. a2. 2010 . . +I NF .  
 3 4 2 0 TH. p3. s1. a2. 2020 . 6. 5430E+5 +I NF .  
 3 4 2 1 TH. p3. s1. a2. 2030 . . +I NF .  
 3 4 2 2 TH. p3. s1. a3. 2010 . . +I NF .  
 3 4 2 3 TH. p3. s1. a3. 2020 . 1. 1544E+6 +I NF .  
 3 4 2 4 TH. p3. s1. a3. 2030 . . +I NF .  
 3 4 2 5 TH. p3. s2. a1. 2010 . . +I NF .  
 3 4 2 6 TH. p3. s2. a1. 2020 . . +I NF .  
 3 4 2 7 TH. p3. s2. a1. 2030 . . +I NF .  
 3 4 2 8 TH. p3. s2. a2. 2010 . . +I NF .  
 3 4 2 9 TH. p3. s2. a2. 2020 . . +I NF .



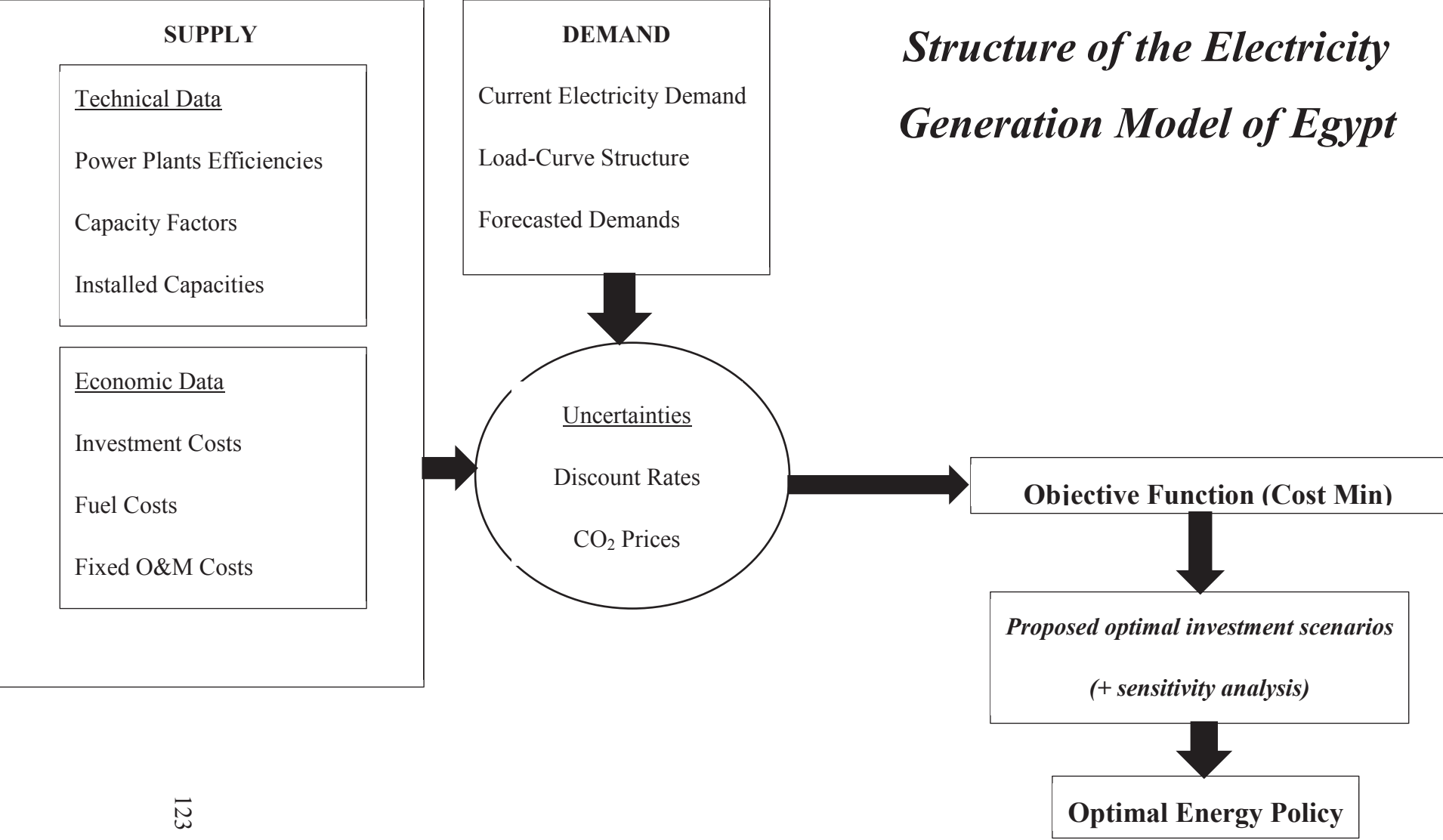
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3 4 3 1 TH p3. s2. a3. 2010 . . . +I NF .	3 4 7 8 CG p1. s3. a3. 2030 . . . +I NF 2. 106
3 4 3 2 TH p3. s2. a3. 2020 . . . +I NF .	3 4 7 9 CG p1. s4. a1. 2010 . . . +I NF 53. 680
3 4 3 3 TH p3. s2. a3. 2030 . . . +I NF .	3 4 8 0 CG p1. s4. a1. 2020 . . . +I NF 24. 864
3 4 3 4 TH p3. s3. a1. 2010 . . . 3. 6063E+6 +I NF .	3 4 8 1 CG p1. s4. a1. 2030 . . . +I NF 16. 851
3 4 3 5 TH p3. s3. a1. 2020 . . . 6. 1331E+6 +I NF .	3 4 8 2 CG p1. s4. a2. 2010 . . . +I NF 6. 710
3 4 3 6 TH p3. s3. a1. 2030 . . . 4. 6281E+6 +I NF .	3 4 8 3 CG p1. s4. a2. 2020 . . . +I NF 3. 108
3 4 3 7 TH p3. s3. a2. 2010 . . . 3. 6792E+6 +I NF .	3 4 8 4 CG p1. s4. a2. 2030 . . . +I NF 2. 106
3 4 3 8 TH p3. s3. a2. 2020 . . . 6. 2133E+6 +I NF .	3 4 8 5 CG p1. s4. a3. 2010 . . . +I NF 6. 710
3 4 3 9 TH p3. s3. a2. 2030 . . . 4. 7156E+6 +I NF .	3 4 8 6 CG p1. s4. a3. 2020 . . . +I NF 3. 108
3 4 4 0 TH p3. s3. a3. 2010 . . . 3. 6792E+6 +I NF .	3 4 8 7 CG p1. s4. a3. 2030 . . . +I NF 2. 106
3 4 4 1 TH p3. s3. a3. 2020 . . . 6. 2133E+6 +I NF .	3 4 8 8 CG p2. s1. a1. 2010 . . . +I NF .
3 4 4 2 TH p3. s3. a3. 2030 . . . 4. 7156E+6 +I NF .	3 4 8 9 CG p2. s1. a1. 2020 . . . 5. 1945E+5 +I NF .
3 4 4 3 TH p3. s4. a1. 2010 . . . +I NF .	3 4 9 0 CG p2. s1. a1. 2030 . . . 2. 2082E+5 +I NF .
3 4 4 4 TH p3. s4. a1. 2020 . . . +I NF .	3 4 9 1 CG p2. s1. a2. 2010 . . . +I NF .
3 4 4 5 TH p3. s4. a1. 2030 . . . +I NF .	3 4 9 2 CG p2. s1. a2. 2020 . . . 5901. 696 +I NF .
3 4 4 6 TH p3. s4. a2. 2010 . . . +I NF .	3 4 9 3 CG p2. s1. a2. 2030 . . . +I NF .
3 4 4 7 TH p3. s4. a2. 2020 . . . +I NF .	3 4 9 4 CG p2. s1. a3. 2010 . . . +I NF .
3 4 4 8 TH p3. s4. a2. 2030 . . . +I NF .	3 4 9 5 CG p2. s1. a3. 2020 . . . 9. 3272E+5 +I NF .
3 4 4 9 TH p3. s4. a3. 2010 . . . +I NF .	3 4 9 6 CG p2. s1. a3. 2030 . . . 6. 7166E+5 +I NF .
3 4 5 0 TH p3. s4. a3. 2020 . . . +I NF .	3 4 9 7 CG p2. s2. a1. 2010 . . . +I NF .
3 4 5 1 TH p3. s4. a3. 2030 . . . +I NF .	3 4 9 8 CG p2. s2. a1. 2020 . . . +I NF .
3 4 5 2 CG p1. s1. a1. 2010 . . . 3. 4655E+5 +I NF .	3 4 9 9 CG p2. s2. a1. 2030 . . . +I NF .
3 4 5 3 CG p1. s1. a1. 2020 . . . 6. 8024E+5 +I NF .	3 5 0 0 CG p2. s2. a2. 2010 . . . +I NF .
3 4 5 4 CG p1. s1. a1. 2030 . . . 6. 4332E+5 +I NF .	3 5 0 1 CG p2. s2. a2. 2020 . . . +I NF .
3 4 5 5 CG p1. s1. a2. 2010 . . . +I NF .	3 5 0 2 CG p2. s2. a2. 2030 . . . +I NF .
3 4 5 6 CG p1. s1. a2. 2020 . . . 1685. 232 +I NF .	3 5 0 3 CG p2. s2. a3. 2010 . . . +I NF .
3 4 5 7 CG p1. s1. a2. 2030 . . . +I NF .	3 5 0 4 CG p2. s2. a3. 2020 . . . +I NF .
3 4 5 8 CG p1. s1. a3. 2010 . . . 5. 8664E+5 +I NF .	3 5 0 5 CG p2. s2. a3. 2030 . . . +I NF .
3 4 5 9 CG p1. s1. a3. 2020 . . . 9. 5725E+5 +I NF .	3 5 0 6 CG p2. s3. a1. 2010 . . . +I NF .
3 4 6 0 CG p1. s1. a3. 2030 . . . 9. 5725E+5 +I NF .	3 5 0 7 CG p2. s3. a1. 2020 . . . 5. 6714E+5 +I NF .
3 4 6 1 CG p1. s2. a1. 2010 . . . +I NF 53. 680	3 5 0 8 CG p2. s3. a1. 2030 . . . 2. 3542E+5 +I NF .
3 4 6 2 CG p1. s2. a1. 2020 . . . +I NF 24. 864	3 5 0 9 CG p2. s3. a2. 2010 . . . +I NF .
3 4 6 3 CG p1. s2. a1. 2030 . . . +I NF 16. 851	3 5 1 0 CG p2. s3. a2. 2020 . . . 4. 0422E+5 +I NF .
3 4 6 4 CG p1. s2. a2. 2010 . . . +I NF 6. 710	3 5 1 1 CG p2. s3. a2. 2030 . . . 57695. 616 +I NF .
3 4 6 5 CG p1. s2. a2. 2020 . . . +I NF 3. 108	3 5 1 2 CG p2. s3. a3. 2010 . . . +I NF .
3 4 6 6 CG p1. s2. a2. 2030 . . . +I NF 2. 106	3 5 1 3 CG p2. s3. a3. 2020 . . . 3. 6512E+5 +I NF .
3 4 6 7 CG p1. s2. a3. 2010 . . . +I NF 6. 710	3 5 1 4 CG p2. s3. a3. 2030 . . . 15041. 664 +I NF .
3 4 6 8 CG p1. s2. a3. 2020 . . . +I NF 3. 108	3 5 1 5 CG p2. s4. a1. 2010 . . . +I NF 53. 680
3 4 6 9 CG p1. s2. a3. 2030 . . . +I NF 2. 106	3 5 1 6 CG p2. s4. a1. 2020 . . . +I NF 24. 864
3 4 7 0 CG p1. s3. a1. 2010 . . . +I NF 53. 680	3 5 1 7 CG p2. s4. a1. 2030 . . . +I NF 16. 851
3 4 7 1 CG p1. s3. a1. 2020 . . . +I NF 24. 864	3 5 1 8 CG p2. s4. a2. 2010 . . . +I NF 6. 710
3 4 7 2 CG p1. s3. a1. 2030 . . . +I NF 16. 851	3 5 1 9 CG p2. s4. a2. 2020 . . . +I NF 3. 108
3 4 7 3 CG p1. s3. a2. 2010 . . . +I NF 6. 710	3 5 2 0 CG p2. s4. a2. 2030 . . . +I NF 2. 106
3 4 7 4 CG p1. s3. a2. 2020 . . . +I NF 3. 108	3 5 2 1 CG p2. s4. a3. 2010 . . . +I NF 6. 710
3 4 7 5 CG p1. s3. a2. 2030 . . . +I NF 2. 106	3 5 2 2 CG p2. s4. a3. 2020 . . . +I NF 3. 108
3 4 7 6 CG p1. s3. a3. 2010 . . . +I NF 6. 710	3 5 2 3 CG p2. s4. a3. 2030 . . . +I NF 2. 106

3 5 2 4 CG p3. s1. a1. 2010 . . . +I NF .	3 5 7 1 TG p1. s2. a1. 2030 . . . +I NF 16. 851
3 5 2 5 CG p3. s1. a1. 2020 . . . +I NF .	3 5 7 2 TG p1. s2. a2. 2010 . . . +I NF 6. 710
3 5 2 6 CG p3. s1. a1. 2030 . . . +I NF .	3 5 7 3 TG p1. s2. a2. 2020 . . . +I NF 3. 108
3 5 2 7 CG p3. s1. a2. 2010 . . . +I NF .	3 5 7 4 TG p1. s2. a2. 2030 . . . +I NF 2. 106
3 5 2 8 CG p3. s1. a2. 2020 . . . +I NF .	3 5 7 5 TG p1. s2. a3. 2010 . . . +I NF 6. 710
3 5 2 9 CG p3. s1. a2. 2030 . . . +I NF .	3 5 7 6 TG p1. s2. a3. 2020 . . . +I NF 3. 108
3 5 3 0 CG p3. s1. a3. 2010 . . . +I NF .	3 5 7 7 TG p1. s2. a3. 2030 . . . +I NF 2. 106
3 5 3 1 CG p3. s1. a3. 2020 . . . +I NF .	3 5 7 8 TG p1. s3. a1. 2010 . . . +I NF 53. 680
3 5 3 2 CG p3. s1. a3. 2030 . . . +I NF .	3 5 7 9 TG p1. s3. a1. 2020 . . . +I NF 24. 864
3 5 3 3 CG p3. s2. a1. 2010 . . . +I NF .	3 5 8 0 TG p1. s3. a1. 2030 . . . +I NF 16. 851
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3 5 3 9 CG p3. s2. a3. 2010 . . . +I NF .	3 5 8 6 TG p1. s3. a3. 2030 . . . +I NF 2. 106
3 5 4 0 CG p3. s2. a3. 2020 . . . +I NF .	3 5 8 7 TG p1. s4. a1. 2010 . . . +I NF 53. 680
3 5 4 1 CG p3. s2. a3. 2030 . . . +I NF .	3 5 8 8 TG p1. s4. a1. 2020 . . . +I NF 24. 864
3 5 4 2 CG p3. s3. a1. 2010 . . . +I NF .	3 5 8 9 TG p1. s4. a1. 2030 . . . +I NF 16. 851
3 5 4 3 CG p3. s3. a1. 2020 . . . +I NF .	3 5 9 0 TG p1. s4. a2. 2010 . . . +I NF 6. 710
3 5 4 4 CG p3. s3. a1. 2030 . . . +I NF .	3 5 9 1 TG p1. s4. a2. 2020 . . . +I NF 3. 108
3 5 4 5 CG p3. s3. a2. 2010 . . . +I NF .	3 5 9 2 TG p1. s4. a2. 2030 . . . +I NF 2. 106
3 5 4 6 CG p3. s3. a2. 2020 . . . +I NF .	3 5 9 3 TG p1. s4. a3. 2010 . . . +I NF 6. 710
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3 5 5 2 CG p3. s4. a1. 2020 . . . +I NF .	3 5 9 9 TG p2. s1. a2. 2010 . . . +I NF .
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3 5 5 7 CG p3. s4. a3. 2010 . . . +I NF .	3 6 0 4 TG p2. s1. a3. 2030 . . . +I NF .
3 5 5 8 CG p3. s4. a3. 2020 . . . +I NF .	3 6 0 5 TG p2. s2. a1. 2010 . . . +I NF .
3 5 5 9 CG p3. s4. a3. 2030 . . . +I NF .	3 6 0 6 TG p2. s2. a1. 2020 . . . +I NF .
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3 5 6 2 TG p1. s1. a1. 2030 . . . +I NF .	3 6 0 9 TG p2. s2. a2. 2020 . . . +I NF .
3 5 6 3 TG p1. s1. a2. 2010 . . . +I NF .	3 6 1 0 TG p2. s2. a2. 2030 . . . +I NF .
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3 5 6 5 TG p1. s1. a2. 2030 . . . +I NF .	3 6 1 2 TG p2. s2. a3. 2020 . . . +I NF .
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3 5 6 7 TG p1. s1. a3. 2020 . . . 3. 2593E+5 +I NF .	3 6 1 4 TG p2. s3. a1. 2010 . . . +I NF .
3 5 6 8 TG p1. s1. a3. 2030 . . . 3. 2593E+5 +I NF .	3 6 1 5 TG p2. s3. a1. 2020 . . . +I NF .
3 5 6 9 TG p1. s2. a1. 2010 . . . +I NF 53. 680	3 6 1 6 TG p2. s3. a1. 2030 . . . +I NF .
3 5 7 0 TG p1. s2. a1. 2020 . . . +I NF 24. 864	3 6 1 7 TG p2. s3. a2. 2010 . . . +I NF .

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 3 6 2 5 TG p2. s4. a1. 2030 . . +I NF 16. 851  
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 3 6 2 9 TG p2. s4. a3. 2010 . . +I NF 6. 710  
 3 6 3 0 TG p2. s4. a3. 2020 . . +I NF 3. 108  
 3 6 3 1 TG p2. s4. a3. 2030 . . +I NF 2. 106  
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 3 6 4 3 TG p3. s2. a1. 2030 . . +I NF .  
 3 6 4 4 TG p3. s2. a2. 2010 . . +I NF .  
 3 6 4 5 TG p3. s2. a2. 2020 . . +I NF .  
 3 6 4 6 TG p3. s2. a2. 2030 . . +I NF .  
 3 6 4 7 TG p3. s2. a3. 2010 . . +I NF .  
 3 6 4 8 TG p3. s2. a3. 2020 . . +I NF .  
 3 6 4 9 TG p3. s2. a3. 2030 . . +I NF .  
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 3 6 5 1 TG p3. s3. a1. 2020 . . +I NF .  
 3 6 5 2 TG p3. s3. a1. 2030 . . +I NF .  
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 3 6 5 5 TG p3. s3. a2. 2030 . . +I NF .  
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 3 6 5 7 TG p3. s3. a3. 2020 . . +I NF .  
 3 6 5 8 TG p3. s3. a3. 2030 . . +I NF .

3 6 5 9 TG p3. s4. a1. 2010 . . +I NF .  
 3 6 6 0 TG p3. s4. a1. 2020 . . +I NF .  
 3 6 6 1 TG p3. s4. a1. 2030 . . +I NF .  
 3 6 6 2 TG p3. s4. a2. 2010 . . +I NF .  
 3 6 6 3 TG p3. s4. a2. 2020 . . +I NF .  
 3 6 6 4 TG p3. s4. a2. 2030 . . +I NF .  
 3 6 6 5 TG p3. s4. a3. 2010 . . +I NF .  
 3 6 6 6 TG p3. s4. a3. 2020 . . +I NF .  
 3 6 6 7 TG p3. s4. a3. 2030 . . +I NF .  
 3 6 6 8  
 3 6 6 9 LOWER LEVEL UPPER MARGI NAL  
 3 6 7 0  
 3 6 7 1 ---- VAR z -I NF 2. 375E+11 +I NF .  
 3 6 7 2  
 3 6 7 3 **z cout (total cost)**  
 3 6 7 4  
 3 6 7 5  
 3 6 7 6 \*\*\*\* REPORT SUMMARY : 0 NONOPT  
 3 6 7 7 0 I NFEASI BLE  
 3 6 7 8 0 UNBOUNDED  
 3 6 7 9  
 3 6 8 0  
 3 6 8 2  
 3 6 8 3  
 3 6 8 4 USER: 10 User Li cense  
 S141201: 0912AO- W N  
 3 6 8 5 RUEI L - Magasi n General DC346  
 3 6 8 6 Li cense for teachi ng and research  
 at degree granti ng i nstitutions  
 3 6 8 7  
 3 6 8 8  
 3 6 8 9 \*\*\*\* FI LE SUMMARY  
 3 6 9 0  
 3 6 9 1  
 I nput  
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 ear ch\ Thesi s\ Egypt \ mode»  
 I ec  
 3 6 9 2 \_ v 2 \_ C O 2 \_ d y n . g m s  
 3 6 9 3 Out put  
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 2\_CO2\_dyn. I st

# *Structure of the Electricity Generation Model of Egypt*



## **Appendix 2-E**

### *Nile's flow sharing challenges*

The Grand Ethiopian Renaissance Dam on the Blue Nile in Ethiopia, now halfway finished, raise many questions whether nations around can finally find ways to share it or not? A recent joint statement by the leaders of Egypt, Ethiopia and Sudan pledges cooperation and no substantial downstream harm. This is very critical for Egypt as the dam will control around two-thirds of the water on which the country depends. But for the joint agreement to be meaningful, these countries will need serious and constructive technical analysis. Poor assessment of the technical issues such as annual rainfall and minimum flows for keeping a proper downstream water quality, can put on danger any sort of agreement and lead to conflicts with unpredictable intensity, given that, in the past, Egypt has been even willing to go to war to protect its water.

This is because the flow rate of Nile is climatic roulette. It experiences periods of abundant water and of significant drought since thousands of years ago. But the stakes are much higher now as the population of Egypt is almost 90 million and continues to grow. Egypt's Aswan High Dam, downstream from the Ethiopian dam, contributes to moderate these fluctuations, but a second large dam and its reservoir higher upriver are going to really complicate the water management. Currently Egypt receives almost all its water from the Nile, around 60 billion cubic meters per year, slightly above the amount provided for in its agreement with Sudan. That amounts to the withdrawal of 700 cubic meters per capita per year.

The monsoon rains in Ethiopia that will feed the new dam come largely during just three months; hence by storing that water, the new dam will moderate and smooth out the flow of the Blue Nile, the 900 mile long headstream of the Nile itself. It will also generate huge amounts of power, the income of which could finance development in Ethiopia – except that transmission lines for exporting the electricity are not yet being constructed.

Sudan will also benefit by using the more stable flow of water from the new dam to raise its agricultural productivity. This will let Sudan, which is situated between Egypt and Ethiopia, to finally employ its full treaty portion of river water, which in turn will reduce what is available to Egypt.

All three countries stand to benefit if they work together. The dam's huge storage capacity could help both Sudan and Egypt during drought years. And if Egypt were to agree to buy the electricity that the new dam will generate (and to build the transmission lines to connect to it, perhaps with international help), then Ethiopia will benefit economically from stored water that has to flow downstream ultimately. Therefore, a solid and detailed agreement based on proper reservoir operation policy, power trading, dam safety and irrigation practices is much-needed. (J.H. Lienhard & N.M. Strzepek, The New York Times 2015)

## **Chapter 3: On the Economic Optimization of National Power Generation Mix in Iran**

## Résumé

La planification énergétique peut être caractérisée comme un problème de décision d'investissement. Les investisseurs utilisent de nombreuses méthodes différentes pour traiter ces problèmes. L'une des méthodes la plus courante est basée sur la théorie du portefeuille de Markowitz par laquelle les investisseurs tentent de maîtriser les risques et de maximiser la performance du portefeuille en vertu de divers résultats économiques volatils. Ce chapitre explique les idées de la théorie du portefeuille et analyse leurs principales applications dans un pays producteur de pétrole et de gaz naturel. Nous allons illustrer comment le parc de production d'électricité en Iran peut être influencé par une addition supplémentaire de ressources nucléaires et renouvelables. En comparaison avec les mix électriques dominés par les ressources fossiles, des portefeuilles efficaces de production d'électricité peuvent réduire considérablement les coûts de production tout en incorporant une plus grande part d'énergies décarbonées dans le mix. Les résultats optimaux pour le mix électrique Iranien montrent que par rapport aux mix basés sur les ressources fossiles, il existe de nombreuses structures de production avec de plus grandes parts de non-fossiles (à la fois nucléaires et renouvelables) à des coûts et des risques égaux ou même inférieurs. D'ailleurs, si nous prenons également en considération les recettes d'exportation de combustibles fossiles libérés (coût d'opportunité des combustibles), cette conclusion devient encore plus évidente.

En outre, notre modèle d'analyse du portefeuille reflète l'interrelation des coûts (covariances) parmi les alternatives de production d'électricité et leur impact sur les coûts et les risques du portefeuille final. Les résultats montrent que le portefeuille typique de la génération d'électricité en Iran, basé sur des ressources fossiles, offre peu de diversification. Bien que cela puisse isoler le risque aléatoire, comme les enjeux entourant le développement de la filière nucléaire Iranienne, il fournit peu de couverture contre le risque systématique des mouvements du prix du pétrole et du gaz, qui historiquement ont été fortement corrélés.

Mots-clés: Portefeuille de la Production d'Electricité; Iran; Diversification



## **Abstract**

Energy planning can be characterized as an investment-decision problem. Investors use many different methods for treating such problems. One of the most common methods is based on the Markowitz's portfolio theory by which investors try to manage risk and maximize their portfolio performance under variety of volatile economic outcomes. This chapter explains essential portfolio theory insights and analysis their application in an oil and gas producing country. We will illustrate how different electricity generation mixes can be influenced by additional share of nuclear and renewable sources. In comparison to the fossil dominated mixes, efficient power generation portfolios can dramatically reduce the generation costs while containing larger shares of decarbonized power units in the mix. The optimal results for the Iranian generation mix demonstrate that compared to the fossil-based mixes, there exist many generating mix structures with larger non-fossil shares (both nuclear and renewable) at equal or even lower expected costs and risks. Moreover, if we also take into consideration the export revenues of released fossil fuels (opportunity cost of fuels) this conclusion becomes even more affirmative.

Moreover, our portfolio model analysis reflects the cost inter-relationship (co-variances) among generating alternatives and their impact on the final portfolio costs and risks. The results illustrate that the typical Iranian gas and fuel generating portfolio offers little diversification. While it may insulate from random risk, such as Iranian nuclear issues, it provides little insulation from the systematic risk of oil and gas price movements, which have historically been highly correlated.

Keywords: Power Generation Portfolio; Iran; Diversification

## **Iran's Economic Outlook and Recent Political Development**

Currently Iran's economy is going through an extremely difficult period. GDP contracted in 2012 for the first time since the early 1990s, under the weight of US sanctions, which are supported by many other major economies. While sanctions have long been in place, they have become more severe since 2010 in response to Iran's alleged nuclear program. The sanctions are targeting Iran's energy sector in particular, as hydrocarbon products accounted for almost 80% of Iranian exports and government revenues in 2010. Furthermore, sanctions have become more effective because they are not only targeting Iran directly but also countries or companies that trade with Iran. For example, the EU placed a ban in 2012 on insurance for tankers carrying Iranian crude. The result has been that oil exports have more than halved in the past few years, a blow to Iran's fiscal position.

The imposition of sanctions and the collapse in exports are causing knock-on effects that will have serious repercussions in both short and long terms. The value of Iran's currency, the Rial, has depreciated by over 80% since late 2011, causing a sharp increase in the price that Iran must pay for imported goods. This has added to inflation that was already high following the progressive removal of energy subsidies that began in December 2010. As a result, inflation hit 37.5% in July 2013. Aside from stoking social unrest, high inflation levels reduced consumer purchasing power, thereby reducing domestic consumption and contributing to the short-term economic slowdown.

The surprise election of Dr. Hassan Rouhani as Iran's next president signals a possible change in the country's external relations and economic policies from recent years. Rouhani's moderate tone resonated with the majority of voters who turned out in record numbers (72.2% of an estimated 50 million voters) to reject the election of more conservative candidates.

The new political leadership will focus on tackling the country's economic crisis after Iran has suffered under crippling sanctions over the past two years, which pushed the inflation rate to 36%, increased youth unemployment to 28% and more than halved the value of the Iranian Rial against the dollar since July 2010. In order to revive the economy, Rohani will have to restart bilateral talks with the US on nuclear issues to get international sanctions removed and to mitigate their permanent damage to the country's industrial growth.

## **Iran Oil and Gas Sector**

Iran is the second largest oil producer in the Middle East and plans to significantly increase output through developing a number of oil and gas fields in the Persian Gulf and through enhancing the recovery rate with gas injection technology. This is a very ambitious plan given that external investment is constrained under US and EU sanctions, unattractive buy-back contract conditions, ageing assets and chronic under-investment in petroleum infrastructure. The largest oil fields are Ahwaz, Gachsaran and Marun, which are located onshore and account for about one third of Iran's oil current production. Oil exploration, production, transportation and exports are managed and operated by various units of the National Iranian Oil Company (NIOC). The NIOC, through its affiliates, has a high degree of control over oil development projects. Buy-back contracts with Iranian oil companies must be signed by international oil companies to develop gas fields in Iran. This has tended to result in lengthy delays as Iranian companies struggle to find capital. To date, there have been twelve buy back deals with foreign companies but only Asian NOCs remain in the existing field developments, given the exodus of IOCs from Iran. Oil and gas infrastructure of Iran is illustrated in figure 3-1.

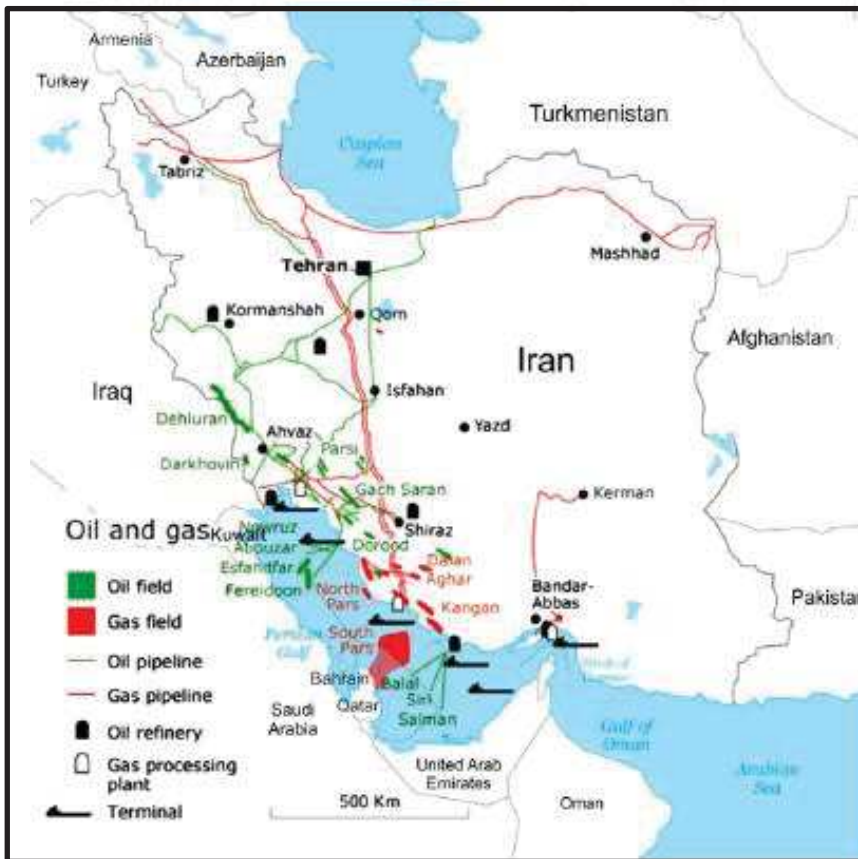


Figure 3-1

(Source: Fanack 2012)

Although Iran has the second largest gas reserves behind Russia, the country is expected to be challenged in exploiting these gas resources. Similar to the oil sector, external investment constraints will be the major impediment to the development of the gas sector. Iran's remaining commercial gas reserves are estimated to be 170 trillion cubic feet and are mainly found offshore in the giant South Pars gas field which is part of the same structure that Qatar has developed successfully (the Qatari side is called the North Field). Foreign companies must enter into buy-back contracts with NIOC (similar to the oil sector) to develop gas fields in Iran. A number of foreign companies had agreements for the development of South Pars including Phases 2&3 (Total, Petronas and Gazprom), Phases 4&5 (Agip and Petro Pars) and Phases 6-8 (Statoil and Petro Pars). Although South Pars phases 11, 13 and 14 were due to be developed, the IOC participants have since been removed from gas production projects.

Current natural gas production is dominated by four onshore non-associated gas fields (Khangiran, Kangan, Nar and the Parsian group) and the first five phases of South Pars. Unlike Qatar's success in developing its gas reserves, Iran has been unable to support its plans to expand supply capacity and to become a major gas exporter. While sales gas production has increased from 56 bcm in 2000 to 138 bcm in 2010, Iran now faces some choices how to invest in the gas sector to maintain or increase production capacity.

Although Iran is a large gas producer, the country will continue to be a net importer over the next years. Iran imports gas via pipelines from Turkmenistan to supply Iran's northeast, which has no direct pipeline connection with Iran's producing fields in the South. While some imported gas is also going to Tehran, the densely populated area around Teheran in the country's centre is mainly supplied via pipelines from the South. Iran currently exports gas only to Turkey via long-term pipeline contracts, which will expire in 2025.

### **Iran's Power Sector Overview**

Gas is the dominant fuel for Iran's electricity generation as it provided 76% of total power generation in 2010, while oil and hydro supplied 20% and 4%, respectively (figure 3-2). Gas-fired generation grew at 7% per annum over 2000-10, spurred by low gas prices (figure 3-3). A severe drought caused hydro power generation to plummet in 2008-09 and electricity from hydro power to drop from 18 TWh in 2007 to 7 TWh in 2009. The shortage of hydro generation was offset by an increase in gas-fired power generation. Frequent power outages resulted from insufficient hydro power supply during the drought, which could not meet quickly rising power demand. Since then, a significant program of state investment has been implemented to boost installed power capacity in order to avoid power shortage in the future. Hydro power generation started to rise again in 2011 as water levels returned to normal.

Iran's electricity generation capacity reached 65 GW in 2011 and the country's generation plants are owned and operated by the company TAVANIR. Hydro generation capacity is owned and operated by then Iran Water and Power Resources Development Company or by Independent Power Producers (IPPs). Electricity production from TAVANIR supplies around 90% of Iran's total electricity generation. Any power produced by IPPs must be sold to

TAVANIR under long-term contracts of around 25 years. The government does intend to establish a competitive wholesale market and allow direct sales to large end-users, but we believe it is highly unlikely that this will happen soon given the country's poor track record for privatization efforts over a number of years.

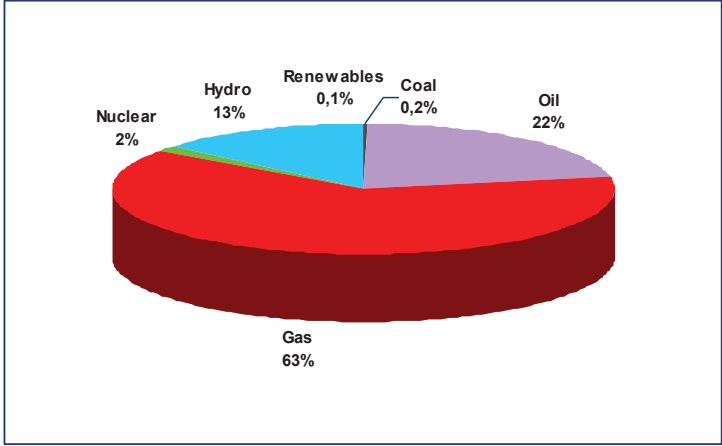


Figure 3-2: Electricity production composition in Iran in 2010

(Source: IEA & BP Statistics)

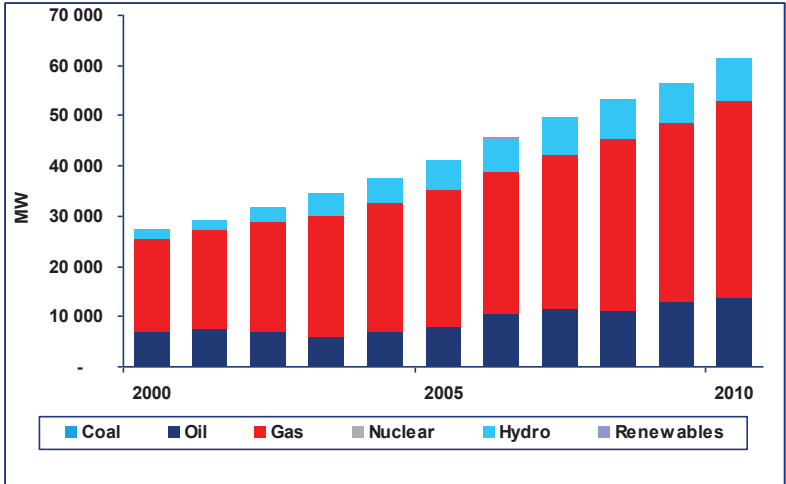


Figure 3-3: Fuel inputs to electricity generation from 2000 to 2010

(Source: IEA & BP Statistics)

Half of the total electricity demand in Iran goes for residential and commercial sectors, while industrial demand takes the second position with around 30% of the total domestic demand (figure 3-4). These shares remained almost intact for a decade between 2000 and 2010, whereas the total demand of the country increased by around 80% proportionally for all the sectors (figure 3-5).

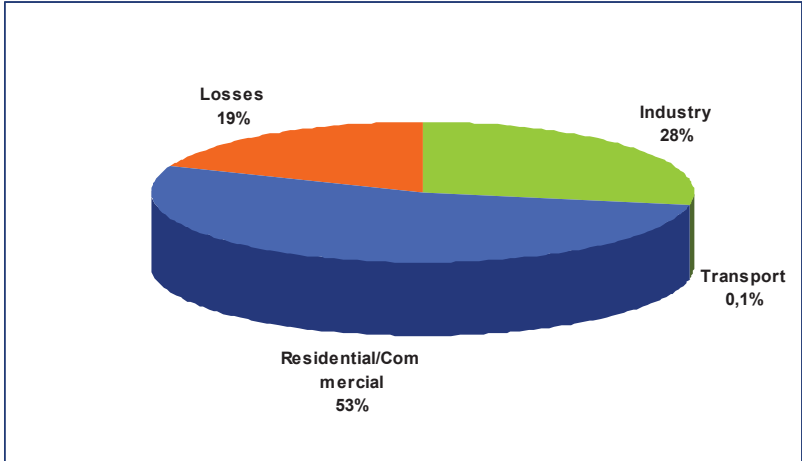


Figure 3-4: Electricity demand in 2010  
(Source: IEA & BP Statistics)

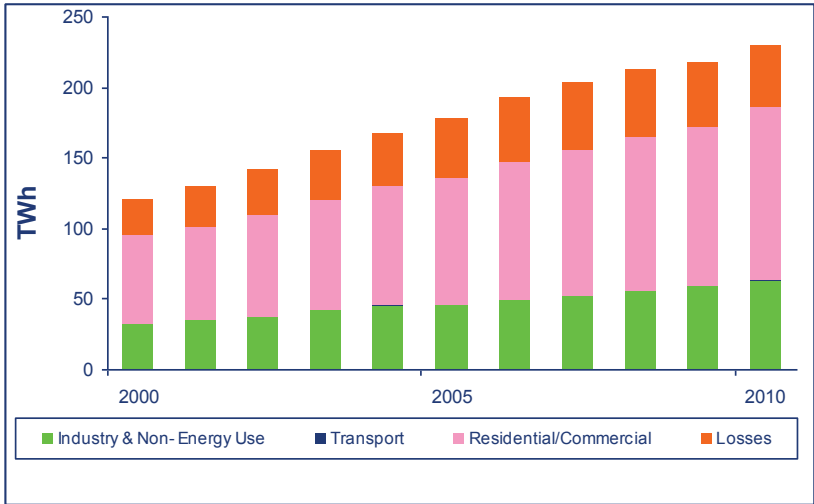


Figure 3-5: Electricity demand evolution from 2000 to 2010  
(Source: IEA & BP Statistics)

Iran exports electricity to Armenia, Pakistan, Turkey, Iraq, and Afghanistan and the country's net electricity exports have increased noticeably over the past years. Although Iran's exports could be negatively impacted by rising domestic power prices when subsidies will be further removed, we expect the trend of rising electricity exports to continue over the forecast period as long as the domestic electricity generation and transmission infrastructure in neighbouring countries (Iraq, Pakistan, Afghanistan) remains underdeveloped.

### **The History of the Electric Power Industry in Iran**

The history of electricity dates back to 1885 when the first dynamo came into service in Iran. This machine with the capacity of 3 KW was used to light the royal court of Tehran, the capital of the country. This occurred 3 years after the inauguration of the first commercial electric lighting entity by Edison in the New York City. 8 years later, a 12hp generator was installed in the Mashhad city (north east of Iran) by the private sector. Also at that time, the first license for establishing commercial electric lighting was granted (for lighting only during evening hours) and the first power plant inaugurated in 1906. Since that time, during around 40 years, electric power was considered as a luxury product used only for lighting with small number of consumers all around the country. The private sector became active in this business and supply facilities were installed by private institutions. After World War II, the government became actively involved in the electrification of the country and started to supply power with subsidized prices. Iran Power Generation & Transmission Company (TAVANIR) established and private sector gradually banned from investing in electricity business. Thereafter, the main objective of the government was to cover all potential electricity consumers and started to install large number of combined-cycles and hydraulic power plants.

Finally, since 90s, the government decided to gradually decentralize and privatize the electricity sector and persuading investment by private entities for bringing more competition into the sector, leading to possible reduction in the prices, and helping the electricity business to move toward financial self-reliance.



Moreover, according to the Article 44 of the Iran's constitutional law, Ministry of Energy must release and transfer the ownership of its several power plants to the private sector and facilitate the liberalization process leading competitive electricity markets.

### **Electricity Market in Iran**

Iran's power market was launched in 23 October 2003. It was based on a mandatory pool model and all producers and consumers should send their bids one day ahead, before 10am, to the market. In this market 32 generating entities and almost 43 distribution companies participate in wholesale energy trade each day. Once the power purchase and sale offers have been accepted, they will be matched by the market operator that administrates financial transactions and shares out production and demand among different parties involved in the auction. To provide a close and effective supervision on the electricity market of Iran, Electricity Market Regulatory Board has been established. This entity is independent of TAVANIR Company and includes seven expert persons of the power industry assigned every two years by the Energy Minister. Ancillary service markets in Iran's electricity market are evolving gradually. Primary frequency control market was introduced on 22 May 2007 along with voltage support services (reactive power) and black start services.

### **Wind Energy Situation in Iran**

Persians were the first people to construct the first wind mills around 200BC. Some of those historic mills are still on operation in rural areas of Khorasan province in North East of Iran. Iran is blessed with diversified and four season climate and besides having deserts; it is also a mountainous land with Caspian Sea on the North and Persian Gulf & Oman Sea in the South. Due to this geographical position, the country benefits from various tropical wind flows coming from Central Asia during winters and Indian Ocean during summer seasons.

Iran's first experience in installing and using modern wind turbines backs to 1994. Two sets of 500KW NORD-TANK turbines were installed in Manjil and Roodbar sites (Alamdari et al. 2011).

Manjil and Binalood are major wind sites of Iran with installed capacity of 94MW (Mousavi et al. 2011). Almost all of the wind plants in the country are state owned and private investors have not yet been involved in this technology. High investment costs, financing problems, lack of long-term governmental support and of course the low prices of electricity, due to heavily subsidized natural gas, are the most important barriers in front of private interventions. Evolution of wind capacity in Iran since 1997 is shown in figure 3-6.

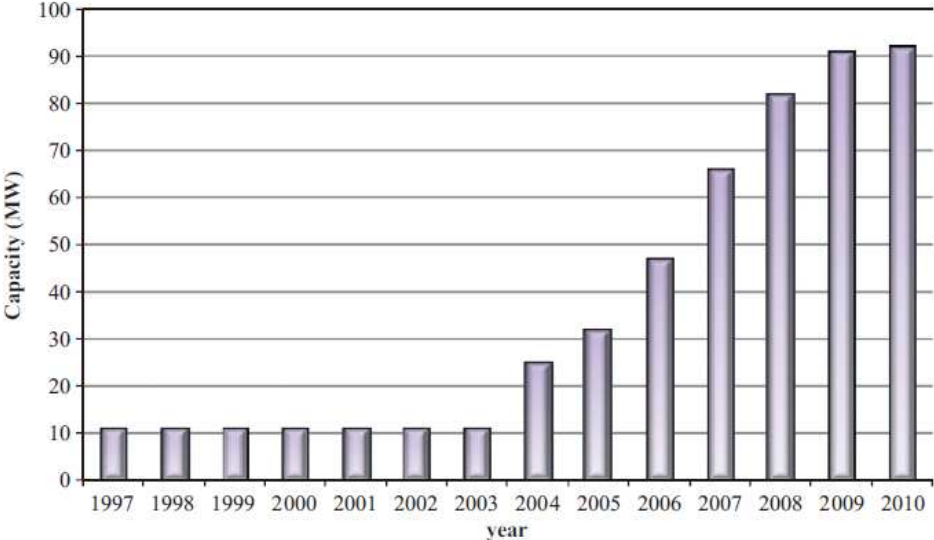


Figure 3-6: Iran wind installed power plants 1997-2010  
 (Source: Iran Renewable Energy Organization SUNA)

Looking at its potential, it is essential that Iran should absolutely not fall behind in the development of this technology. Nevertheless, it is a far journey so as to fill up the technology gaps and to utilize the large wind power potentials.

**Hydropower Development in Iran**

Iran is classified as an arid and semi-arid country because of its long-term average precipitation of around 250mm, which is nearly one-quarter of the world’s average rate. Moreover, the precipitation is not evenly distributed all over the country. The total surface water is around 92bcm of which 27bcm flow into three major basins: Dez, Karkheh and

Karoon rivers basins all located in the South-West of Iran over the Zagros mountain chains where the major hydroelectric projects are located. Northern and Northwestern regions have relevant precipitation and topography for developing small medium-sized hydro plants.

Currently, there are 42 hydroelectric plants on operation in Iran, with total installed capacity of around 8GW and many others with total capacity of almost 7GW are also under construction. Large hydro plants with capacity of more than 100MW cover more than 90% of the installed capacity.

Volume of hydropower is highly variable in Iran and depends on yearly water falls. For example, in 2007 more than 18TWh of power was fed to national grids while this amount was decreased by 72% in 2008 due to unexpected droughts (Ministry of Power Annual report 2008).

There are many water streams in Iran which either go waste or finish at rivers and finally into the sea. Therefore, many small and mini hydro systems can easily be installed to provide locally needed power or to be injected to grids. Unfortunately, these huge potentials of hydro power are not effectively utilized and are even deprived of any further extensive planning.

### **Solar Energy Status in Iran**

Iran enjoys approximately 2800 sunny hours per year as it is located on the world's Sun Belt. Iran's average solar insolation rate is estimated to be around 2000 kwh/m<sup>2</sup>. Figure 3-7 shows the average annual sum of this rate for different regions.

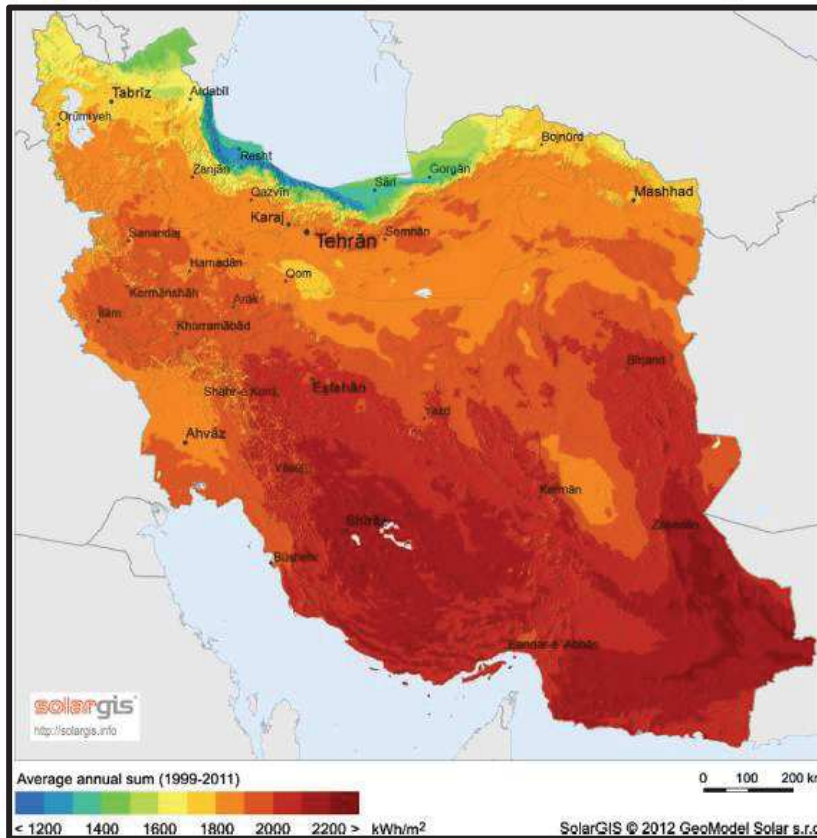


Figure 3-7: Iran solar energy map  
(Source: Solar GIS)

The first in Iran and the largest in Middle East, Shiraz solar power plant will come to full operation by the end of 2015 according to Iran’s Renewable Energy Organization.

### **Biogas and Biomass Energy Status in Iran**

Unlike all other renewable energies which are very site specific, biogas is site independent; Domestic and industrial swage waste, animal waste, 80% of garbage and left over of agricultural products are the main sources of biogas energy in Iran.

All these waste are also great sources of pollution and carriers of many infectious diseases in and around every village and city. The effect can become very dangerous mainly during hot seasons. These are the serious issues mostly faced by developing countries such as Iran.

Hence, the focus of this technology is not only on power generation but also on having a healthy environment.

For the time being, the total installed capacity of biogas power plants in Iran is around 1665 KW and the total gross generation is 5967 GWh. For instance, installed capacity of Shiraz solid waste disposal equals 1060 KW. However, during the past years the utilization capacity of the site was only 450 KW, due to the portion and specification of the waste disposal.

## **Methodology**

Hereby, we describe essential ideas related to portfolio theory and discuss their application in the analysis of the Iranian electricity generation mix. We adopted this methodology for the Iranian case as the electricity sector in Iran is a quasi-competitive system. It is also more privatized than Egypt or Saudi Arabia. This is already explained in detail in the general introduction of this work. Besides, energy diversity is the main focus of late between Iranian energy authorities. Portfolio-based models are very much adapted to treat energy diversity issues.

Therefore stand-alone least cost approach does not necessarily provide the most optimal solution for the Iranian generation mix and we should adopt an optimization model based on both cost and risk minimization process.

By applying this approach we will illustrate how electric power generation mixes can benefit from additional shares of non-fossil generating units. In comparison to fossil dominated mixes, efficient portfolios could decrease the total generating cost while including greater non-fossil (nuclear and renewables) shares in the mix. This improves also energy security. Though counter-intuitive, this conclusion is completely consistent with fundamental finance theory. As a matter of fact, under dynamic and uncertain environments, the relative value of producing technologies should be determined not by evaluating alternative resources but alternative resource-portfolios.

## Mean Variance Portfolio Approach

Markowitz' mean variance portfolio theory is a probabilistic approach which could be used to value and optimize fuel mix diversity. This theory defines portfolio risk as total risk (including both random and systematic fluctuations) measured by the standard deviation of periodic historic returns. An efficient portfolio includes the smallest risk for a given level of expected return or vice-versa, the biggest expected return for a given level of risk. The process contains making an optimal portfolio generally by using historical measures of risk, returns (costs) and of course the correlation coefficients between various assets to be considered in the portfolio.

By numerical (computer aided) processing the risk (standard deviation), return or cost and correlation coefficients data, it would be possible to produce a number of portfolios for varying amounts of return having the least risk level from asset classes consisted. They are called efficient/optimal portfolios, which situate on the so called efficient frontier. Efficient frontier of two risky assets and the set of optimal portfolios are shown in figure 3-8.

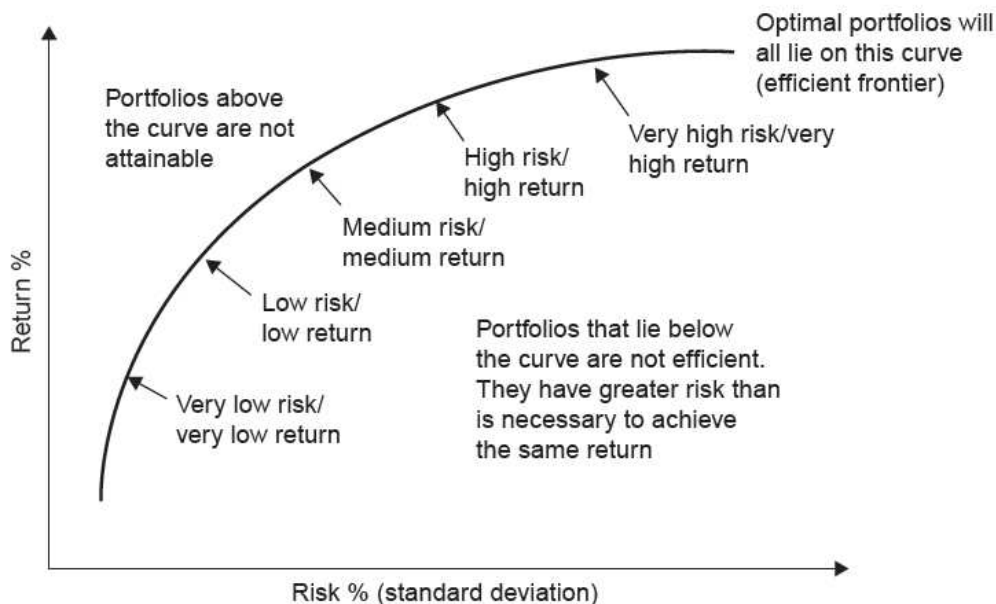


Figure 3-8

Then according to this efficient frontier, the investor simply needs to choose his desired level of risk. Actually, mean-variance portfolio theory suggests not a single efficient portfolio, but a range of optimal choices. Based on their risk aversion and preferences, investors will choose a risk-return combination.

Initially, mean-variance portfolio theory developed only for financial applications. But it can also be used for power generation assets to determine the efficient portfolio for a country or generation company, discussed in detail in Awerbuch & Berger (2003) and Roques et al. (2008). Awerbuch and Berger (2003) suggest that the relative value of producing assets should be determined not by evaluating alternative assets, but by evaluating alternative asset portfolios. Hence, energy planning entities need to focus less on stand-alone least cost alternative and more on building optimal power generating portfolios.

In 1976, Bar-Lev and Katz applied mean variance portfolio theory to fossil fuel supply for US electric utilities. By focusing on a regional approach, they constructed the theoretical efficient frontier of fossil fuel mix for various regulated utilities and compare it with the real experience of the power utilities. They found out that most of the utilities portfolios were situated on the efficient frontier but with very high level of risk and rate of return. They interpreted this as a consequence of the cost-plus regulatory frame work encouraging electric utilities to operate in a very risky manner.

Humphreys and McClain (1998) also used portfolio theory to propose the most optimal energy mix in the USA to reduce risks associated with unanticipated energy price shocks. They note that American electric utilities have approached more efficient points of generation since the 1980s, and that the switch toward natural gas took place in the 1990s were driven by strong wish for higher returns to investment.

Awerbuch (2000) analysis the US gas-coal generation mix and demonstrating that more wind, solar and other renewables with zero variable costs in the portfolio will lead to overall risk and cost reductions, even if their stand-alone costs might be higher.

Awerbuch and Berger (2003) attempt to determine the optimal European technology mix, taking into account not only fuel price risk but also construction period risks and operation

and maintenance risks. They found that EU-2010 mix is coupled with higher rate of risk and return compare to EU-2000 generation mix.

Jansen et al. (2006) use portfolio approach for analysing the electricity generation mix of Netherlands. Their study concentrates on fuel price uncertainty and is based on generation costs. They conclude that more diverse production portfolios are generally associated with lower risks for the same amount of returns. Especially those which contain more fixed-cost renewables and nuclear which have a low covariance with the fossil-fuel technologies' costs.

More recent studies like Roques et al. (2008) focus more on a private investor prospective. They conclude that in the absence of long-term power purchase contracts in the UK efficient portfolios differ greatly from socially optimal ones. They found that there is a little motivation of diversification for private investors as there is a high correlation between electricity, gas and carbon prices. This kind of conclusion raises questions about how policy makers and regulators should adapt the market frame work to assure system diversity and security of supply.

### **Portfolio Theory Application in Power Generation Investment**

Traditional power generation investment valuations approaches such as the famous levelized cost method, are mainly based on stand-alone analysis. But generation technologies have various risks and return patterns, as such that there are many valuable potential advantages in constructing a diversified portfolio of power plants. Mean variance portfolio theory applications provide more information for a country policy maker and utilities regarding many critical risks in liberalized and quasi-liberalized power systems.

Portfolio theory application is highly used by financial investors to construct high return and low-risk asset portfolios under different economic contexts. In one word, investors have learned that an optimal portfolio contains no unnecessary risk to its expected return-on-investment. Portfolio theory could be very suitable for planning and evaluating electric power portfolios and strategies as the process is too similar to one used by financial investors seeking to maximize their profit under minimization of the variety of unpredictable risks. In a similar way, it is essential to conceive of power generation not in terms of the levelized cost



of a specific technology today, but in terms of its portfolio cost. In other words, when we apply portfolio theory to power generation planning and strategy, fossil and non-fossil alternatives are evaluated not on the bases of their stand-alone costs but on the basis of portfolio cost which is their contribution to total portfolio producing cost relative to their contribution to total portfolio risk.

If we look at the example of two assets from social planner view point (Iranian government in our case), the generating cost would be the relevant measure. As a matter of fact generating cost (\$/KWh) is the inverse of a return (KWh/\$); that is, a return in terms of physical output per unit of monetary input.

In this case, expected portfolio cost is the weighted average of the individual expected generating costs for the two technologies:

$$E(C_p) = X_1 \times E(C_1) + X_2 \times E(C_2)$$

Where  $X_1$  and  $X_2$  are fractional shares of the two technologies in the generating mix and  $E(C_1)$  and  $E(C_2)$  are respectively their expected levelized costs per KWh.

Expected portfolio risk,  $E(\sigma_p)$  is the expected year-to-year variation in generation cost. It is also a weighted average of the individual technology cost variances, as tempered by their covariance:

$$E(\sigma_p) = (X_1^2 \sigma_1^2 + X_2^2 \sigma_2^2 + 2X_1 X_2 \rho_{12} \sigma_1 \sigma_2)^{0.5}$$

Where  $X_1$  and  $X_2$  are the fractional shares of the two technologies in the mix,  $\sigma_1$  and  $\sigma_2$  are the standard deviations of the holding period returns (HPRs) of the annual costs of technologies and  $\rho_{12}$  is their correlation coefficient.

Portfolio risk is estimated as the standard deviation of HPRs of the future cost of generation defined as:

$$HPR = (V_2 - V_1) / V_1$$

In which  $V_2$  is the ending value and  $V_1$  is the starting value of the costs. In case of fuel cost for example,  $V_2$  can be considered as the cost of fuel in year  $(t + 1)$  and  $V_1$  as the cost in year  $(t)$ .

In other words, HPR, measures the rate of change in the cost stream from one year to the next. A detailed discussion is given in Berger (2003).

The correlation  $\rho$  is an indicator of diversity in a sense that smaller  $\rho$  among portfolio components generates greater diversity, as measured by an absence of correlation between portfolio constituents. Adding a zero fuel cost technology to a risky generating mix, lowers expected portfolio cost at any level of risk, even if this technology costs more (Awerbuch 2006).

A fixed cost technology (with zero fuel cost) has  $\sigma_i=0$ , or very near to zero. This will decrease considering  $\bar{\sigma}_p$  since two of three items in the  $E(\bar{\sigma}_p)$  equation decrease to zero. And it is clear that  $\bar{\sigma}_p$  reduces as  $\rho_{ij}$  falls below one. For example again in case of pure fuel-less, fixed-cost renewable technologies, fuel risk is zero and its correlation with fossil fuel costs is also zero.

### **Modelling Tool and Process**

For the modelling purpose we have used OptQuest and Crystal Ball tools developed by Oracle Enterprise Performance Management System. Firstly we go through the Crystal Ball simulator structure which we use for our cost estimation and modelling purpose and then OptQuest modelling tool will be developed in details so as to reveal the in-depth structure of our portfolio optimization model and of course the results based on already modelled costs structures.

Crystal Ball is a forecasting and risk analysis tool for decision making under uncertainty. Through Monte Carlo simulation technique, Crystal Ball forecasts the entire range of results for a given situation. It also shows us confidence levels, so we can know the likelihood of any specific event taking place. For each uncertain variable in a simulation, we can define the possible values with a probability distribution. A simulation calculates numerous scenarios of a model by repeatedly picking values from the probability distribution for the uncertain variables and using those values for the cell. Distributions and associated scenario input values are called assumptions. After hundreds or thousands of trials, we can view sets of values, the statistics of the results (such as the mean forecast value), and the certainty of any

particular value. Crystal Ball actually is a simulation model that prepares the ground for our optimization model defined in OptQuest.

Traditional search methods work well when finding local solutions around a given starting point with model data that are precisely known. These methods fail, however, when searching for global solutions to real world problems that contain significant amounts of uncertainty. Recent developments in optimization have produced efficient search methods capable of finding optimal solutions to complex problems involving elements of uncertainty. OptQuest incorporates meta-heuristics to guide its search algorithm toward better solutions. This approach uses a form of adaptive memory to remember which solutions worked well before and recombines them into new, better solutions. Since this technique doesn't use the hill-climbing approach of ordinary solvers, it does not get trapped in local solutions, and it does not get thrown of course by noisy (uncertain) model data.

Once we describe an optimization problem (by selecting decision variables and the objective and possibly imposing constraints and requirements), OptQuest invokes Crystal Ball to evaluate the simulation model for different sets of decision variable values. It evaluates the statistical outputs from the simulation model, analyses and integrates them with outputs from previous simulation runs, and determines a new set of values to evaluate. This is an iterative process that successively generates new sets of values. Not all of these values improve the objective, but over time this process provides a highly efficient trajectory to the best solutions. As shown in the following flow chart, the search process continues until it reaches some termination criteria, either a limit on the amount of time devoted to the search or a maximum number of simulations.

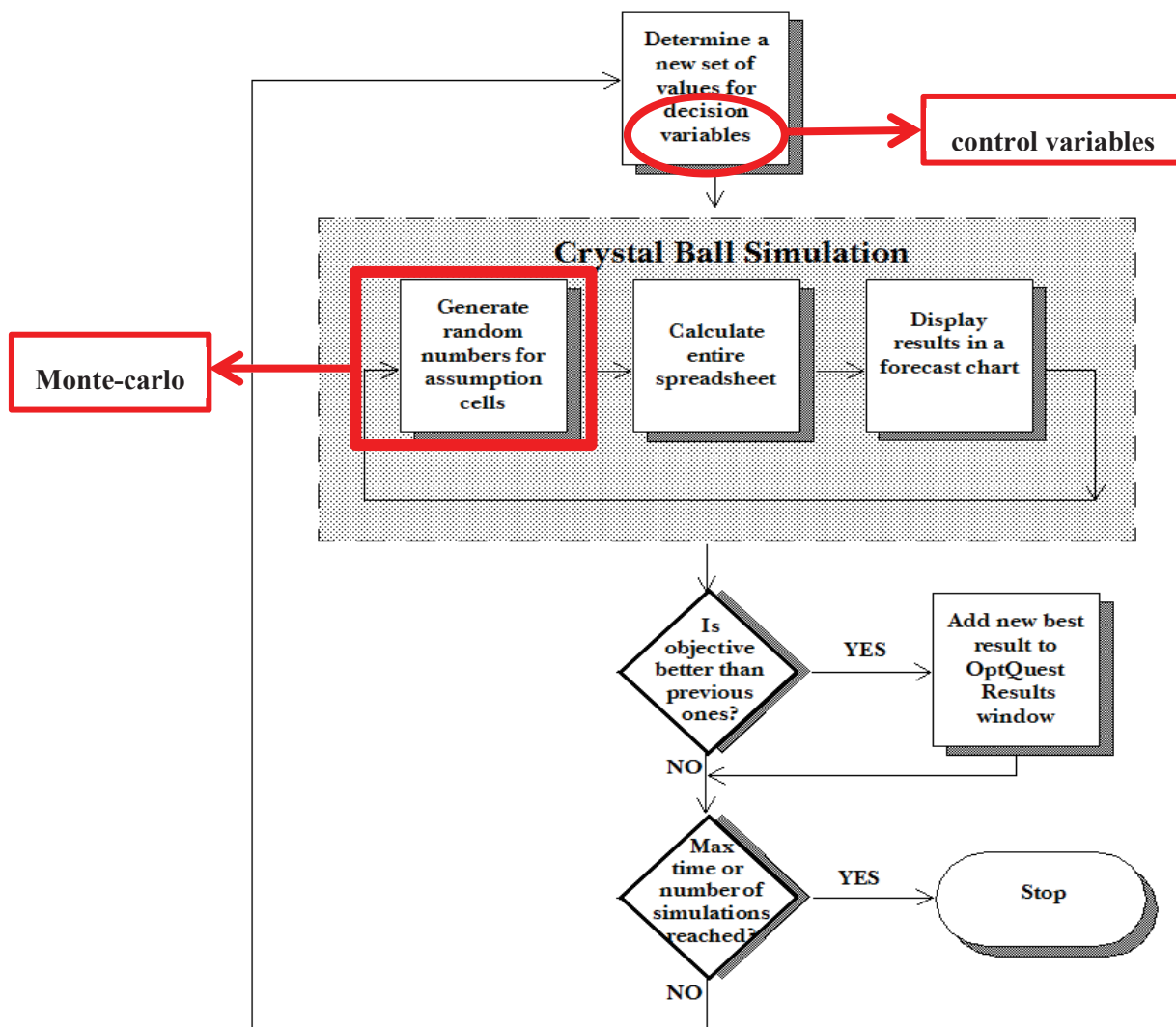


Figure 3-9

An OptQuest optimization model has four major elements: an objective, optional requirements, decision variables (already simulated by Crystal Ball) and optional constraints.

Optimization Objectives: Elements that represents the target goal of the optimization, such as maximizing profit or minimizing cost, based on a forecast and related decision variables.

Requirements: Optional restrictions placed on forecast statistics. All requirements must be satisfied before a solution can be considered feasible.

Decision Variables: Variables over which you have control; for example, the amount of product to make, the number of dollars to allocate among different investments, or which projects to select from among a limited set.

Constraints: Optional restrictions placed on decision variable values. For example, a constraint might ensure that the total amount of money allocated among various investments cannot exceed a specified amount, or at most one project from a certain group can be selected.

The whole stochastic simulation-optimization model to be constructed by Crystal Ball and OptQuest tools would be summarized in the following figure:

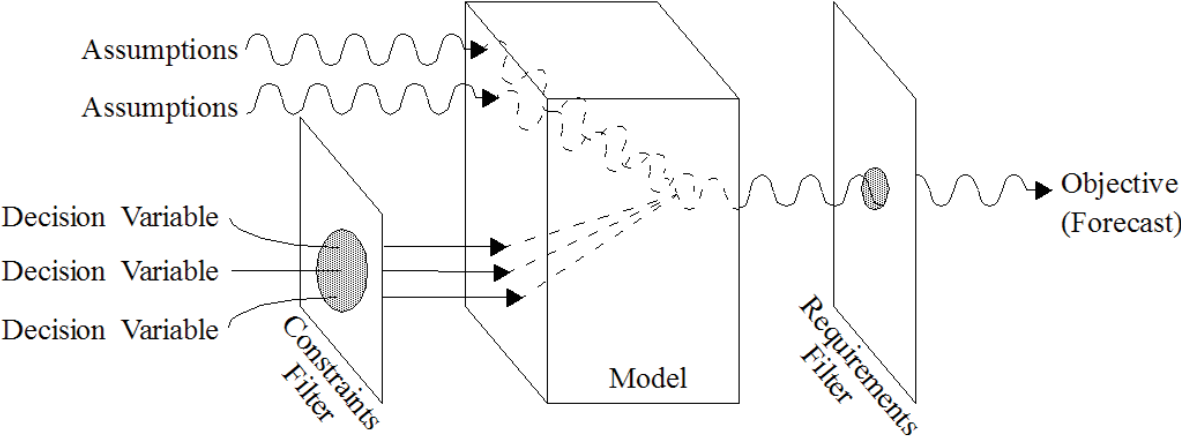


Figure 3-10

## Iranian Power Generation Mix Model

As already mentioned at the beginning of this chapter both renewable and fossil fuel power plants are to be considered for the national electricity generation of Iran. Hence, coal, fuel-oil and natural gas power plants introduced to our model as fossil-based power units. In addition, nuclear power units and renewables (hydro, wind and solar) were also added to the generation mix. Geothermal units were not considered in our modelling because of the non-existence of any influential policy in the ministry agenda.

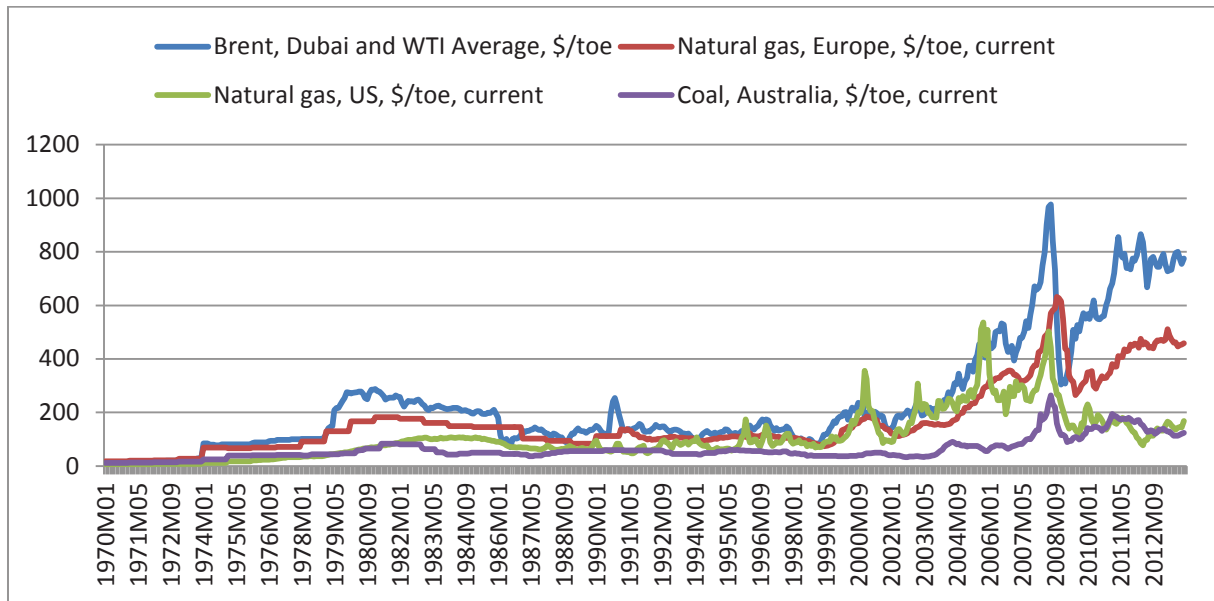
Therefore the total expected portfolio cost of the Iranian mix is given by:

$$E(C_{IranP}) = X_{oil}E(C_{oil}) + X_{gas}E(C_{gas}) + X_{coal}E(C_{coal}) + X_{nuc}E(C_{nuc}) + X_{hydro}E(C_{hydro}) + X_{solar}E(C_{solar}) + X_{wind}E(C_{wind})$$

And the total expected standard deviation (risk) of the portfolio is:

$$E(\sigma_{IranP}) = [ X_{oil}^2 \sigma_{oil}^2 + X_{gas}^2 \sigma_{gas}^2 + X_{coal}^2 \sigma_{coal}^2 + X_{nuc}^2 \sigma_{nuc}^2 + X_{hydro}^2 \sigma_{hydro}^2 + X_{solar}^2 \sigma_{solar}^2 + X_{wind}^2 \sigma_{wind}^2 + 2X_{oil}X_{coal}\rho_{oil,coal}\sigma_{oil}\sigma_{coal} + 2X_{oil}X_{gas}\rho_{oil,gas}\sigma_{oil}\sigma_{gas} + 2X_{oil}X_{nuc}\rho_{oil,nuc}\sigma_{oil}\sigma_{nuc} + 2X_{oil}X_{hydro}\rho_{oil,hydro}\sigma_{oil}\sigma_{hydro} + 2X_{oil}X_{solar}\rho_{oil,solar}\sigma_{oil}\sigma_{solar} + 2X_{oil}X_{wind}\rho_{oil,wind}\sigma_{oil}\sigma_{wind} + 2X_{gas}X_{coal}\rho_{coal,gas}\sigma_{gas}\sigma_{coal} + 2X_{gas}X_{nuc}\rho_{nuc,gas}\sigma_{nuc}\sigma_{gas} + 2X_{gas}X_{hydro}\rho_{hydro,gas}\sigma_{gas}\sigma_{hydro} + 2X_{gas}X_{solar}\rho_{solar,gas}\sigma_{gas}\sigma_{solar} + 2X_{gas}X_{wind}\rho_{wind,gas}\sigma_{gas}\sigma_{wind} + 2X_{nuc}X_{coal}\rho_{coal,nuc}\sigma_{nuc}\sigma_{coal} + 2X_{hydro}X_{coal}\rho_{coal,hydro}\sigma_{coal}\sigma_{hydro} + 2X_{solar}X_{coal}\rho_{coal,solar}\sigma_{coal}\sigma_{solar} + 2X_{wind}X_{coal}\rho_{wind,coal}\sigma_{wind}\sigma_{coal} + 2X_{nuc}X_{hydro}\rho_{nuc,hydro}\sigma_{hydro}\sigma_{nuc} + 2X_{nuc}X_{solar}\rho_{nuc,solar}\sigma_{nuc}\sigma_{solar} + 2X_{nuc}X_{wind}\rho_{nuc,wind}\sigma_{nuc}\sigma_{wind} + 2X_{hydro}X_{solar}\rho_{hydro,solar}\sigma_{hydro}\sigma_{solar} + 2X_{hydro}X_{wind}\rho_{hydro,wind}\sigma_{hydro}\sigma_{wind} + 2X_{solar}X_{wind}\rho_{solar,wind}\sigma_{solar}\sigma_{wind} ]^{0.5}$$

In which  $X_i$  and  $C_i$  are respectively the shares and costs of Iranian power generation technologies. The standard deviation associated with each technology is denoted by  $\sigma_i$  and  $\rho_i$  illustrates the correlation coefficients between various fuels used in related power units. For instance the correlations between fossil fuel prices, calculated based on the last decade monthly-averaged price of fossil commodities, are shown in the below figure.



Correlation analysis of fossil commodities used in the model				
	Brent, Dubai and WTI Average, \$/toe	Natural gas, Europe, \$/toe, current	Natural gas, US, \$/toe, current	Coal, Australia, \$/toe, current
Brent, Dubai and WTI Average, \$/toe	1			
Natural gas, Europe, \$/toe, current	0.942016019	1		
Natural gas, US, \$/toe, current	0.740124098	0.675343067	1	
Coal, Australia, \$/toe, current	0.572281856	0.591320862	0.462094974	1

Figure 3-11

In case of nuclear fuel, we considered the annual average price of natural uranium over the last fifteen years and its correlation with other fossil resources prices. This resulted in a rather high correlation coefficient between coal and nuclear at around 0.4 while natural gas and oil have respectively 0.2 and 0.1 correlation coefficients with nuclear fuels (table 3-1B).

Consequently, the total generating portfolio cost has been constructed based on the weighted average cost distribution of each technology. Costs were defined with normal distributions and their associated means and estimated standard deviations. Details of standard deviation (risk) for each technology for its construction period, fuel cost and O&M costs and correlation coefficients between various technologies are summarized in tables 3-1A and 3-1B.

Technology Risk Estimates / Standard Deviation				
	<u>Construction Period</u>	<u>Fuel<sup>a</sup></u>	<u>Variable O&amp;M</u>	<u>Fixed O&amp;M</u>
Nuclear	0,2	0,15	0,2	0,08
Coal	0,18	0,05	0,2	0,08
Oil	0,1	0,3	0,2	0,08
Gas	0,15	0,3	0,2	0,08
Wind	0,05	0	0,2	0,08
Solar	0,09	0	0,2	0,08
Hydro	0,2	0	0,2	0,08

a. Estimation based on empirical data 2005-2012

Table 3-1A

Correlations Coefficients between Technologies					
	Gas	Coal	Nuclear	Oil	Renewable
Gas	1	0,5	0,2	0,8	0
Coal	0,5	1	0,4	0,5	0
Nuclear	0,2	0,4	1	0,1	0
Oil	0,8	0,5	0,2	1	0
Renewable	0	0	0	0	1

Table 3-1B

Source: TAVANIR, Awerbuch et al. (2010) & Author's estimations

As you can see in the table the standard deviation for fuel costs are all equal to zero for renewable technologies. As there is no requirement for any sort of fossil fuel. Construction period risks vary by unit type and are mainly related to complexity and length of construction period<sup>13</sup>. Fixed cost implies an annual obligation that will be undertaken by an investor as long as sufficient income exists, which make this risk somehow similar to the risk of payments on the company's debt.

As explained previously, the correlation coefficient  $\rho$  is an indicator of diversity. Lower correlation among portfolio components creates greater diversity, which serves to reduce

<sup>13</sup> Nuclear construction period and its related standard deviation is based on the normal situation and contractual relations, even if it was not really the case of the first nuclear power plant (Booshehr) constructed in Iran. The construction period of Booshehr plant took almost 30 years due to the political reasons.



portfolio risk. In general, portfolio risk falls with increasing diversity, as measured by an absence of correlation between portfolio elements. Adding a fixed-cost technology to a risky generating mix serves to lower expected portfolio cost at any level of risk, even if the fixed-cost technology costs more (Awerbuch 2005). In the case of fuel-less renewables, fuel risk is equal to zero and its correlation with fossil fuel costs is also taken as zero.

For each power unit, risk is equal to the year-to-year standard deviation of the holding period returns for main generating cost: capital or construction period risk, fixed and fuel. Fossil fuel standard deviations are estimated from historical data already explained in previous chapters.

The portfolio analysis focuses on the risk of generating costs only. We ignore year-to-year fluctuations in electricity output from wind (or solar) plants, taking the approach that a properly managed wind resource can produce constant annual output.

Future fossil fuel costs and other generating outlays are random statistical variables. While their historic averages and standard deviations are known, they move unpredictably over time. No one knows for sure what the price of gas will be next month, just like nobody knows what the stock markets will do in finance theory. Estimating the generating cost of a particular portfolio presents the same problems as estimating the expected return to a financial portfolio. It involves estimating cost from the perspective of its market risk.

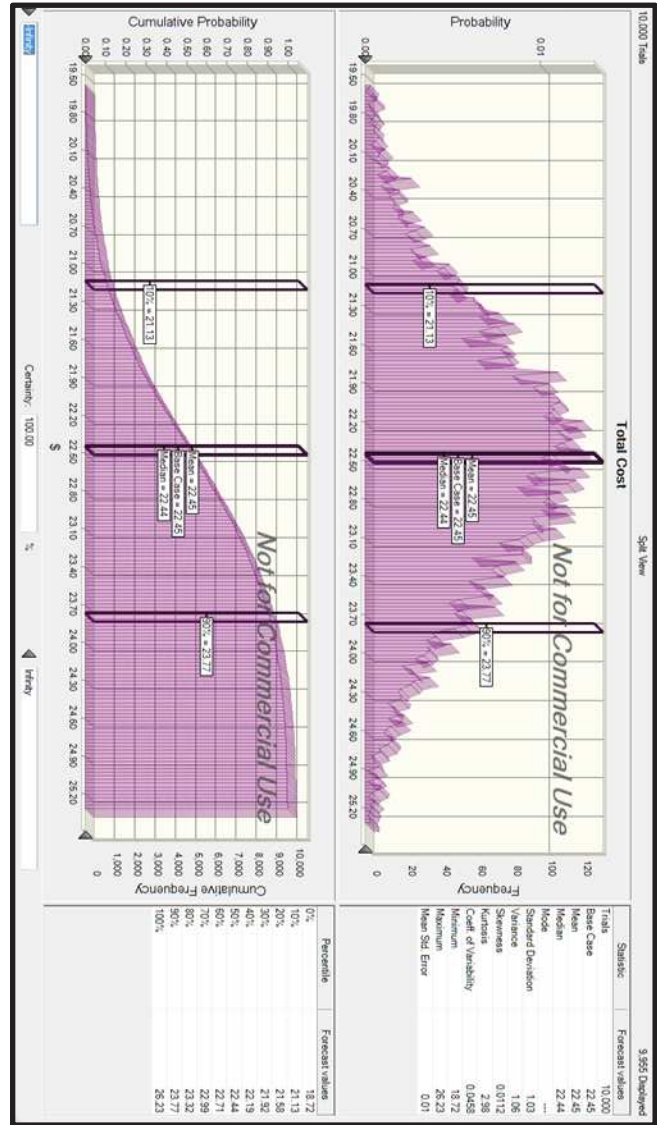
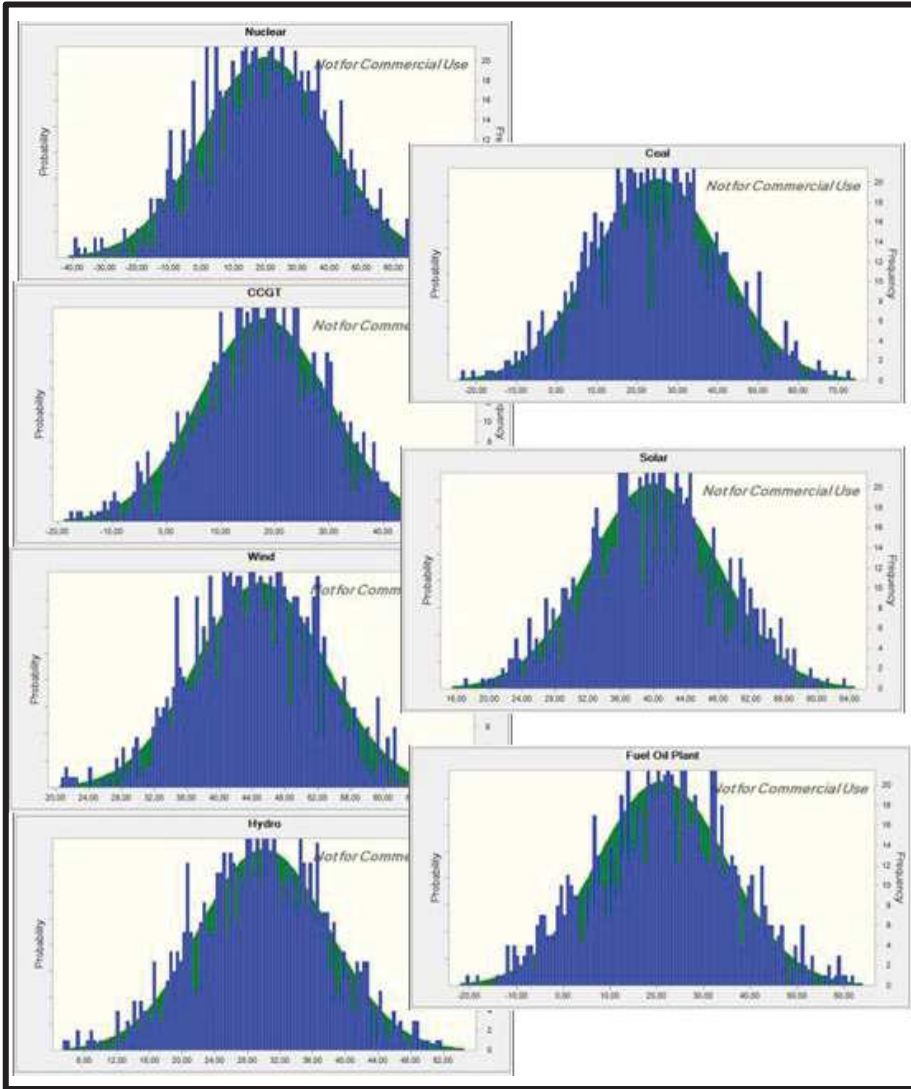
Current approaches for evaluating and planning national energy mixes consistently bias in favour of risky fossil alternatives. Whereas by understating the true value of wind, solar, and similar fixed-cost, low-risk, passive, capital-intensive technologies. The evidence indicates that such technologies offer a unique cost-risk menu along with other valuable attributes that traditional valuation models cannot (Awerbuch, 1995). The evidence further suggests that fixed-cost renewables cost-effectively hedge the fossil price risk as compared to standard financial hedging mechanisms (Bolinger et al. 2004).

The total cost of the portfolio is the sum of all the levelized costs distribution (specific for each technology). Crystal Ball simulation tool, generates the total cost of the portfolio as showed in the below figures.

As a matter of fact, the cost of each power generation unit is given to the model under the normal distribution assumption of the cost distribution with associated mean and variance.

Afterwards, we generate the total cost of the whole portfolio under Monte-Carlo process based on the percentage share of each unit in the portfolio. Details of this total cost modelling process are illustrated in figure 3-12.

*Cost distribution of each power generation unit*



*Total generation cost of the portfolio*

Figure 3-12

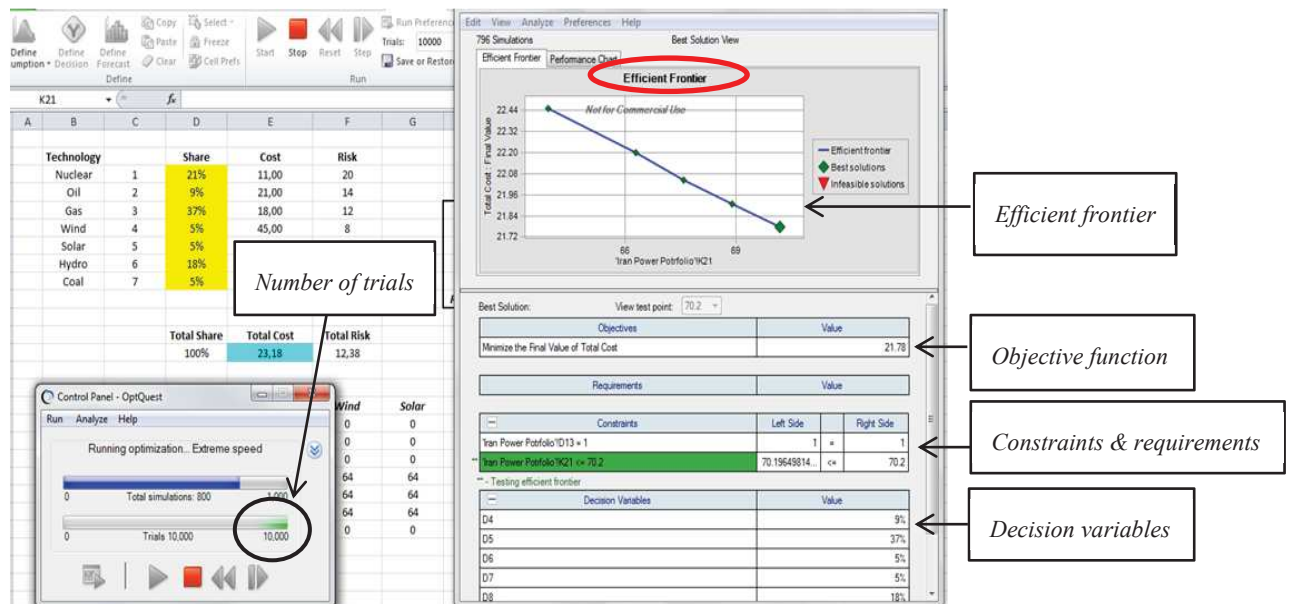
Feasible intervals for technologies' share are also introduced in the model. Intervals are defined according to the techno-economic feasibilities for each power unit. For example, the upper bound of hydroelectricity cannot go beyond 20% due to its saturation level in Iran. Technologies' share-bounds of all power units used in the model are given in table 3-2.

Decision Variable	Lower Bound	Base Case	Upper Bound
Coal	1%	5%	10%
Gas	30%	40%	80%
Hydro	10%	20%	20%
Nuclear	2%	15%	40%
Oil	10%	10%	40%
Solar	1%	5%	30%
Wind	1%	5%	50%

Table 3-2

### Model's Result and Optimal Portfolios

After running the model for around 10,000 trials (iterations), we obtain the following efficient frontier (figures 3-13 and 3-14) for the various generation mix portfolios for the Iranian mix.



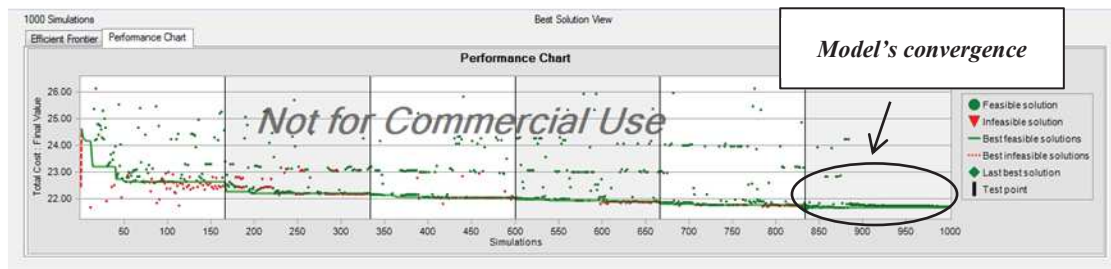


Figure 3-13

Each point on the efficient frontier represents an optimal generation mix scenario based on its related generation total cost and risks. Results show us that the least risky portfolio of power generation has the total cost of electricity generation equals to 26.35 USD/MWh. Least risky portfolio has the largest possible share of hydroelectricity and solar power units while fossil fuel technologies have the least possible shares. In this case, nuclear power share stays at 11%. On the contrary, in the least cost portfolio, at around 13.8 USD/MWh with two times riskier portfolio, nuclear and gas power plants shares are respectively equal to 35 and 36 per cents. Renewable resources, both wind and solar, are at their minimum levels. A comparative analysis of these two max and min costs portfolios, illustrates the impact of the non-fossil power units integration into the national generation mix. The more we decarbonize the mix (via renewables and of course up to the upper bound limit), the less risky portfolio we have.

However, strong penetration of non-fossil power units in the system can increase significantly the total cost of the power portfolio. Central planner can choose among all the possible portfolios on the efficient frontier according to its risk aversion.

In the second step we place the current portfolio of the Iranian power generation mix (data available in figures 3-2 and 3-3) on the cost-risk graph (figure 3-13).

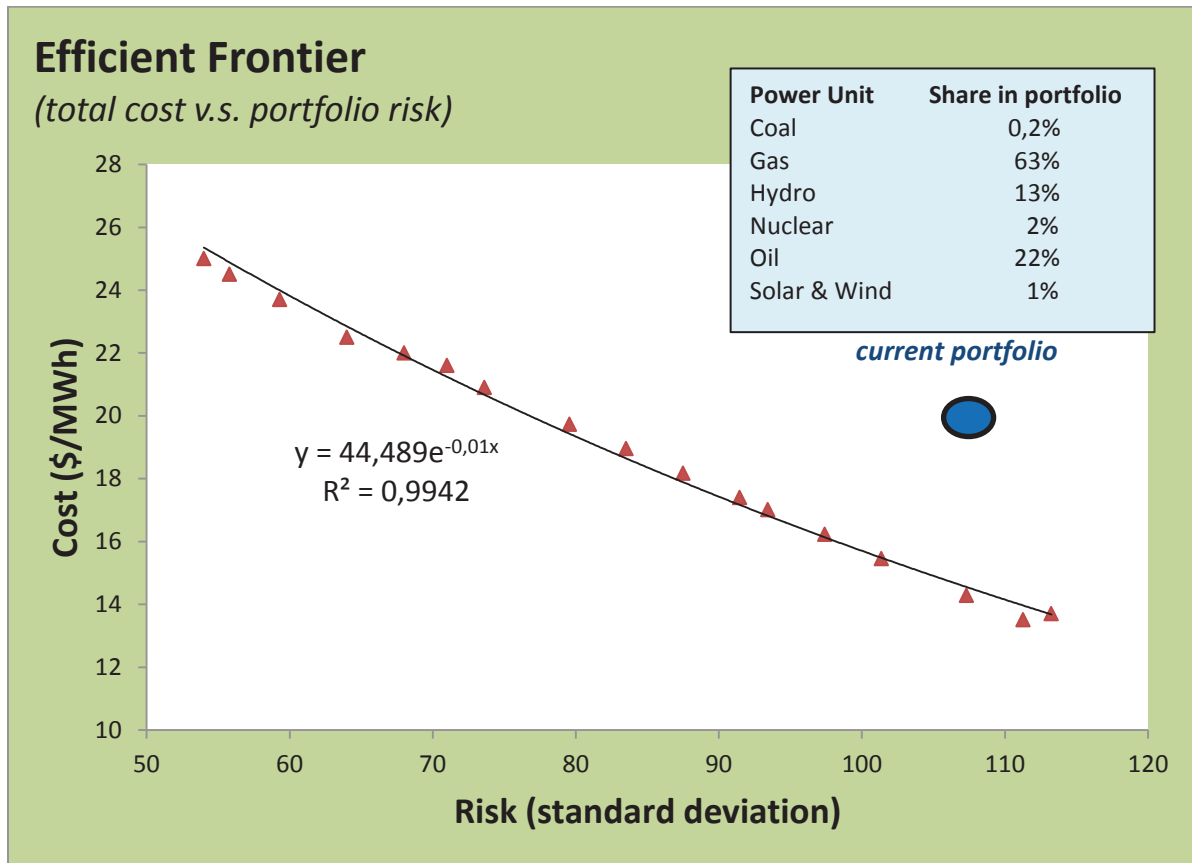


Figure 3-14

We can see that the current Iranian portfolio is not situated on the efficient frontier constructed by the model. Central planner can bring the portfolio to the efficient and optimal frontier by running a trade-off between risk and total cost. Iranian power portfolio could become at least 20% less risky under the current generation cost by following the constant-cost path (trajectory 1 on the figure 3-15) for reaching the efficient border.

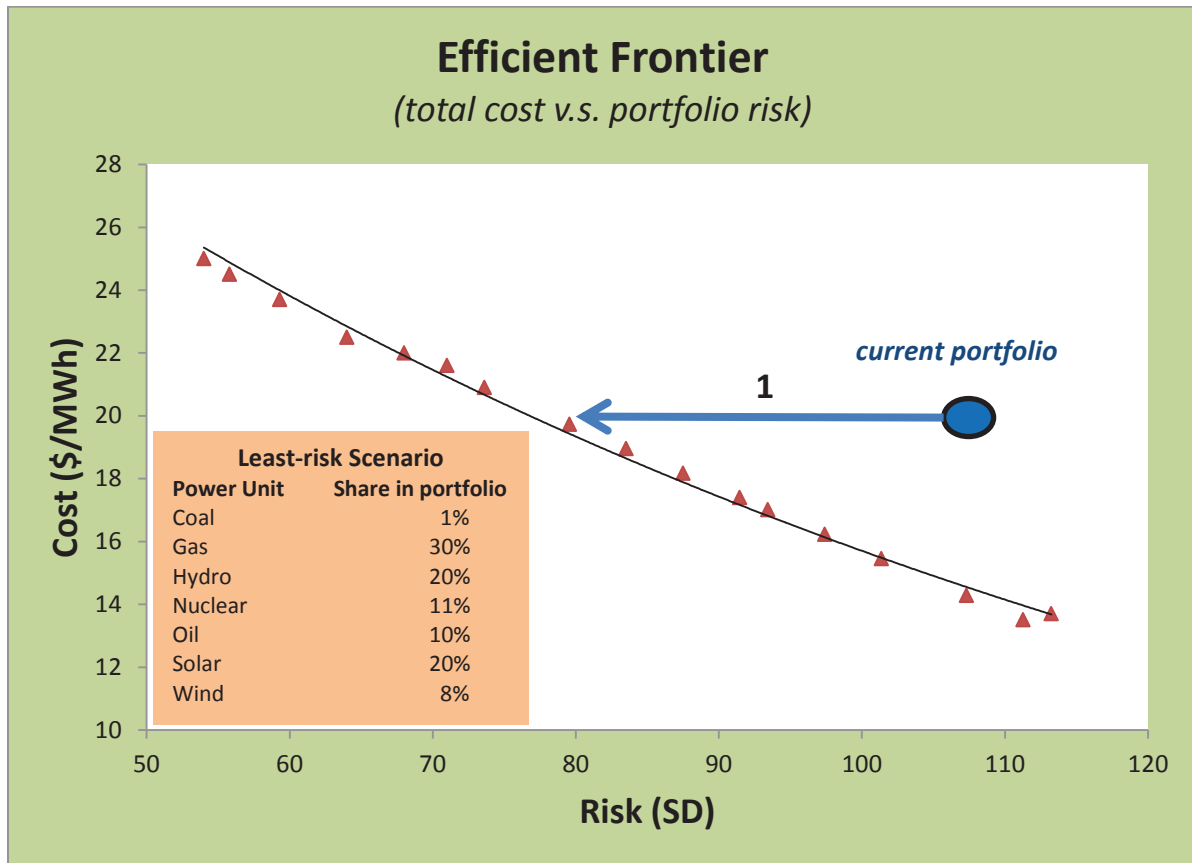


Figure 3-15

This action implies an increase of non-fossil power units share up to 30% in the generation mix (with at least 11% of electricity coming from nuclear). Fuel oil power plants share must be reduced up to 40%, half of their current share. And in case of coal power units, the situation is less dramatic as the model suggests even a small increase of its share up to 1% of the total mix which can be explained by the tendency of the model to raise the diversity of the portfolio and consequently reducing the total risk.

Trajectory 1, is the most risk-averse way of optimizing the Iranian portfolio while there are plenty other existing trade-offs among various risk and cost values. Trajectories 2 and 3 are other examples (figure 3-16). If the planner follows path 3, it will lead to the least cost scenario in which the share of nuclear energy should reach the maximum upper limit and the natural gas units take over just after. What we recommend as the most economic rational

solution is the path 2 which is the median case and contains a fifty-fifty trade-off between risk and cost.

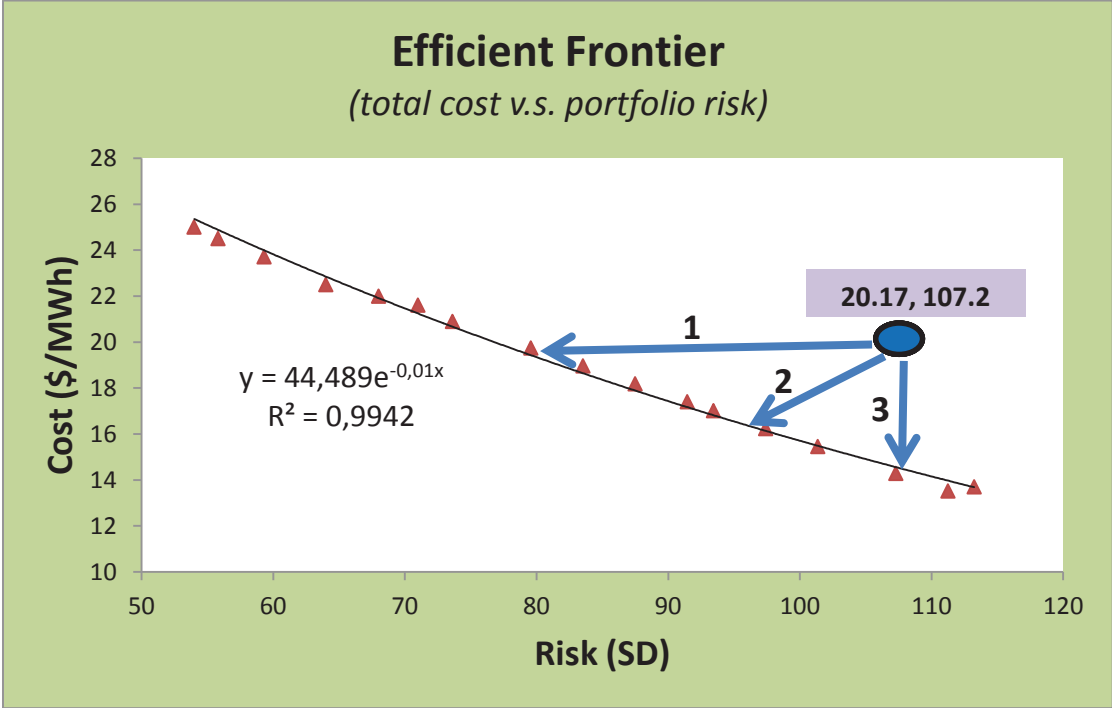


Figure 3-16

Summary of the power generation mix structure of three above-mentioned portfolio possibilities and the current one, are given in table 3-3.

Power Generation Units	Current Portfolio	Least-Cost Scenario	Median Case	Least-Risk Scenario
Coal	0.2%	3%	2%	1%
Gas	63%	36%	33%	30%
Hydro	13%	19%	19%	20%
Nuclear	2%	31%	19%	11%
Oil	22%	9%	10%	10%
Solar	0.05%	1%	12%	20%
Wind	0.05%	1%	5%	8%

Table 3-3



Alike the previous chapters we performed a sensitivity analysis over the fossil fuel price used in the energy system model. We did it for 30% of oil price variation in the international markets compare to our initial input. This will obviously impact the variable costs of power generation in our fossil based power units. As already analysed in the earlier sections of this chapter, oil price variation will also influence the price of other fossil commodities. This in not only the case of natural gas price, which is mainly indexed on oil price, but also that of coal and natural uranium whose prices are in correlation with the oil price.

Fuel price sensitivity analysis was done for the whole portfolio and for every new price assumption. We run the simulation and optimization model so as to generate the new efficient frontiers of our power generation portfolio. For the same reasons explained above, we are mainly interested in the median case. Structures of each optimal electricity generation portfolio are given in table 3-4 under various oil price variation assumptions.

Power Units	$\Delta$ \$ Oil (-30%)	$\Delta$ \$ Oil (-15%)	Median	$\Delta$ \$ Oil (+15%)	$\Delta$ \$ Oil (+30%)
Coal	0.25%	1%	2%	1.5%	1%
Gas	60%	51%	33%	29.5%	20%
Hydro	16%	18%	19%	20%	20%
Nuclear	3%	9%	19%	22%	30%
Oil	20%	13%	10%	6%	2%
Solar	0.5%	6%	12%	14%	17%
Wind	0.25%	2%	5%	7%	10%

Table 3-4

The results show that the increase of oil price can highly promote the non-fossilisation of our power generation portfolio. For instance, in case of 30% increase in the oil price the shares of natural gas and fuel power units in the system can decrease respectively by 16 and 10 per cents. Nuclear and solar power units would be the most optimal and cost-risk efficient production means. Nevertheless, the model still recommends 2% of fuel power units as these units can provide energy diversity and reliable back-up power for intermittent renewables in the system.

On the contrary in case of oil price decrease, the model suggest significant amount of gas and fuel power stations. But still the share of the natural gas in the system is less than that of the current portfolio (63% of gas) which is situated very far from the efficient frontier. This also the case for the power units run by fuel. Finally in this case, we can observe a dramatically decrease of the nuclear and renewable shares. Still their shares are not equal to zero as the model has always the tendency to bring energy diversity and security in the system. To conclude, we can say that under the oil price decrease assumption, the optimal mix would be pushed toward more fossil-based structures consisting highly inter-connected fossil fuels (oil, natural gas and even to some extent coal).

Moreover, higher oil prices in the international markets (and consequently higher natural gas prices) brings more export opportunity for Iran and vice versa. This can also accelerate the impact of oil price variations on the electricity mix structure of Iran. However, we must add that the natural gas export has recently become a very strategic matter due to its geopolitical and technological perspectives. And Iranian energy authorities have always announced keeping this issue as a priority whatever the opportunity cost of natural gas monetization would be elsewhere in other domestic usages, except as feed for petrochemical units providing products also ready for export.

Lastly, we also integrated the CO<sub>2</sub> costs of 10, 15 and 20 €/MWh in the model. The results for each CO<sub>2</sub> cost integration compare to the median optimal scenario without carbon price are given in table 3-5.

Power Generation Units	No CO <sub>2</sub>	CO <sub>2</sub> at 10 €/MWh	CO <sub>2</sub> at 15 €/MWh	CO <sub>2</sub> at 20 €/MWh
Coal	2%	1%	0.7%	0.2%
Gas	33%	26%	21%	17%
Hydro	19%	19.2%	19.5%	20%
Nuclear	19%	26%	31%	34%
Oil	10%	6%	4.5%	2%
Solar	12%	15%	16.3%	18%
Wind	5%	6.8%	7%	8.8%

Table 3-5

The results show that CO<sub>2</sub> cost reacts and influences the power system in the opposite direction of oil price variation. Except for the case of coal which is not recommended neither in case of oil price increase nor CO<sub>2</sub> high costs. We can conclude that a proper CO<sub>2</sub>-cost integration in the system cannot only provide environmental benefits but also dampen the vulnerability of the electricity mix against oil price fluctuations. Yet, there is not still any solid CO<sub>2</sub> reduction policy concerning the power generation sector and for the time being the main focus of Iran in terms of environmental issues is rather on the transport sector than others.

## Conclusion

Today's dynamic and uncertain energy environment of Iran needs planning procedures that accommodate risks and de-emphasize stand-alone electricity generating costs. Procedures that can reflect the cost inter-relationship among various generating alternatives. In this chapter we attempted to construct the efficient portfolio of national power generation for the Iranian electricity sector. This was done under Mean Variance Portfolio (MVP) approach of Markowitz theory, fully explained throughout the chapter.

Mean-variance portfolio theory that we applied in our analysis is well tested and ideally suited to evaluating national electricity strategies (other existing methods are explained in the Appendix 3-A of this chapter). The MVP framework offers solutions that enhance energy diversity and security and are therefore considerably more robust than arbitrarily mixing technology alternatives. MVP illustrates that the typical Iran gas and fuel generating portfolio offers little diversification. While it may insulate from random risk, such as Iranian nuclear issues, it provides little insulation from the systematic risk of oil and gas price movements, which have historically been highly correlated<sup>14</sup> and can dramatically impact the export revenue of the country and opportunity cost of electricity generation.

Given the high degree of uncertainty, the relative value of generating technologies must be determined not by evaluating alternative resources, but by evaluating alternative resource portfolios. Energy analysts and policy makers in oil producing countries face a future that is technologically, institutionally and politically complex and uncertain. In this environment, MVP techniques help establish renewables targets and portfolio standards that make economic and policy sense (Jansen, 2004). They also provide the analytic basis policy-makers need to devise efficient generating mixes that maximize not only the national revenue but also the system security and sustainability. MVP analysis shows that contrary to widespread belief, attaining these objectives need not increase cost. In the case of the Iranian national power generation mix, increasing the non-fossil share, even if it is believed to cost more on a stand-alone basis, reduces portfolio cost-risk and enhances very high energy security. The results showed that the current Iranian generation mix is far from the optimality in terms of cost and

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<sup>14</sup> Increasing use of contracts may mitigate this historical relationship by pricing each fuel more on the basis of its costs. However, history suggests that when shortages for a particular fuel occur, the cost of alternative fossil fuels rises. This is also the case in hydrocarbon producing countries.

diversity. In fact, according to our model's outputs, there is a huge potential of improvement in costs and risks reductions (respectively 15 and 10 per cent) by going toward more non-fossil fuel based portfolio of power generation.

However, any sort of aggressive strategy concerning both cost and risk reduction process, is not recommended as they are negatively correlated to each other. Massive investment in nuclear and other non-fossil resources would highly increase the portfolio's costs and can make the Iranian power sector very vulnerable against technological risks even if the impact on the energy security risk reduction could be very significant. Besides, relying on the current investment trend in the fossil power units can harm the Iranian power sector seriously by increasing the total risk of electricity generation portfolio. Moreover, this will also lead to substantial reduction of hydrocarbon export, as the domestic demand of oil and gas for power generation will continue to rise.

A compromise between fossil and non-fossil sources of power generation would be the most efficient solution for Iran. In the short and medium term Iran should continue to invest in both types of power units while gradually decrease the share of fossil units in the generation mix until reaching the optimal values. Both nuclear and renewable (wind and solar) power plants should gradually become more and more present in the national electricity portfolio of the country. However, this should happen under the condition that the nuclear power units' costs per MWh become at the normal and internationally acceptable rates. If the nuclear costs continue to stay at the same levels as of the first Iranian nuclear power plant in Booshehr (30 years of construction time and tripled investment costs), this conclusion would be totally irrelevant and inconsiderable from economic point of view.

Under any circumstances, investment in solar power must become the priority of the Iranian authorities as Iran with its vast desert areas can benefit from very smooth and reliable solar firms.

Last but not the least, it should not be disremembered that this gradual non-fossilization of the Iran's generation portfolio must be fulfilled in parallel with a solid and efficient policy regarding the decrease and eventually total removal of fossil fuels subsidies. More information and discussions concerning subsidies issue is provided in the last chapter of this work.

## **Appendix 3-A**

### ***The concept of energy diversity and optimal power mix***

We argue that greater diversity in terms of power generation enhances the solidity of power system to fossil fuel supply shocks and therefore yields more economic and specially security of supply benefits. Nevertheless, a diverse power system does not entirely guarantee 100% supply security for the system. We will also argue that this concept of energy diversity in the power sector is ill-defined and needs more clarifications. In fact, it is not still clear what must be diversified and how to quantify the cost and benefit of increased diversity.

In this appendix we review different modern approaches to value the diversity of a power system. Even if there have been many attempts to introduce diversity indicators, such efforts suffer from not appropriately quantifying the costs associated with greater diversity. Here, we discuss how some analytical tools come from the financial literature have been used so as to quantify the costs and benefits of energy diversity and what are their pros and cons.

The main question is: “How to define the diversity of a power system?” Essentially the concept of diversity (as applied to power systems) flourished from political tensions and discussions about the reliability of fossil fuel imports. All over this study we analyse the power systems of oil and gas producing countries not really dependent, except recently for Egypt, on the fuel imports from outside the country. Hence, my first argument against the application of under mentioned methodology is based on this reality.

The thumb nail rule of diversity is too simple “Don’t put all your eggs in one basket”. This includes not only the mix of fuels used to generate power but also plant technologies, operators and environmental aspects. Most of the existing methodologies focus on the fuel mix that as we have already explained is not really the most important issue when we are dealing with hydrocarbon producing countries.

The most famous valuation methods of energy diversity in power systems have been borrowed from Finance theories. These include both static valuation methods such as Mean-Variance Portfolio (used in our study) and Value at Risk and dynamic ones, such as the Real Options method. In the following, we describe briefly the concept of these two methods with the existing assumptions hiding behind them. In 1990s, value at risk method gained increasing

popularity in the finance and banking sectors. It evaluates the worst case scenario (maximum loss potential) on an investment over a certain period of time and degree of confidence (Bearley and Myers, 2000). This approach works for any portfolio of assets (in our case power plants) when market values are available. Normal distributions are generally considered for price volatilities based on historical data. Thereafter maximum portfolio loss can be calculated for the worse case scenarios with the occurrence probability of 5%. These models are very sensitive to price volatilities, correlations between financial assets and off-course the presumed distribution of price changes. Recent review of the progress in the VaR theories applied in power sector has been realized by Kleindorfer and Li (2005).

Another borrowed concept from financial literature is called Real Options, used for dynamic valuation of energy mix. In simple words, this theory says that when the future is uncertain, it pays to have a broad range of options available and to maintain the flexibility to exercise these options. Real options theory solves the major shortcoming of the static models. It introduces into the model, the ability of a utility to react dynamically under changing market conditions. In its simplest term, real options valuation methods allow for adjustment of the timing of the investment decision. It is therefore well suited to evaluate investments under uncertain condition and cost, as it captures the option value contained in managerial flexibility in the face of future uncertain developments: the greater the uncertainty that can be resolved, the more advantageous it is to wait and thus the higher the option value (Dixit and Pindyck 1994). The most beneficial application of real options method in power industry can be found in the economic analyses of different technologies when fuel prices, CO<sub>2</sub> prices and electricity prices are very uncertain.

Both value-at-risk & real-options models owe their credibility to liberalized, liquid and robust markets which can provide enough reliable data. Hence, they lose gradually their plausibility when we go through more central planning and less liquid markets such as Saudi Arabia, Egypt and Iran. Furthermore, fuel price uncertainty is the main philosophy behind these models which is not indeed the most essential matter for the oil and gas producing countries. Actually other factors such as discount rates, financing, technological challenges and political risks are really the chief elements underlying investment decisions in these regions.

We have discussed the most popular analytical tools (borrowed from finance theories) applicable to power generation mix optimization and valuation. However, it is still unclear what exactly should be diversified and how much diversity is optimal. Because the generation mix diversity is a multi-faceted issue and it is truly challenging to quantify and measure the costs and benefits associated with larger fuel mix diversity.



## **Appendix 3-B**

### *A brief history of the nuclear power in Iran*

Iran's nuclear program dates back to 1957. That year saw a nuclear training center under the auspices of Central Treaty Organization (CENTO) move from Baghdad to Tehran, the opening of the American "Atoms for Peace" exhibit in the city and the announcement of a bilateral agreement between Iran and the USA for co-operation on the peaceful uses of nuclear technology. Nuclear power was born in Iran following the delivery of a 5MW light water research reactor from the United States. For almost a decade Iranian nuclear program remained halted due to the lack of technical and scientific infrastructure for such a technology. It was in 1968 that finally the Atomic Research Center with a working 5MW pool type research reactor was officially opened.

Soon after, the famous AEOI (The Atomic Energy Organization of Iran) created. First debate between AEOI members was the choice of the reactors types (heavy or light) for future nuclear power of the country. Finally, the light water variety has been chosen as they were considered to be the most reliable ones. The second critical decision was who would construct them. Germany (West Germany at that time) and France were chosen after several discussions and meetings. Both countries had excellent nuclear industries and were fairly neutral political choices. A preliminary site for the Iran's first power plant was then chosen, around 20 km south east of Booshehr city on the south western coast of Iran along the Persian Gulf. It would supply electric power to the inland city of Shiraz.

A coastal location was desirable due to the logistics and shipping of equipment and also sea water which could be used as a cooler for the plant. The only challenge was the location's history of earthquakes. The data was passed across to the German firm Kraftwerk Union AG, a joint venture of Siemens AG and AEG Telefunken, which had been selected to build the power plant. Kraftwerk was instructed to make the plant as earthquake-resistant as possible. In late 1975, s of the two 1.196 MW reactors were based on the convoy design and identical to the second reactor unit of the German Biblis nuclear power plant.

The first reactor was scheduled to be finished by 1980 and the second one by 1981. At that time the German government was so eager to enter the Iranian market. The domestic German

market was already saturated and the USA had cornered most of the rest of Europe, thus the developing world was the main target and Iran's oil wealth made it the ideal client. By the time the revolution came in 1979, the first reactor (Booshehr I) was 85% complete (on the schedule for its 1981 completion date) and the second (Booshehr II) partially complete. AEOI's plans for up to 20 nuclear reactors meant that multiple projects had to be commissioned simultaneously and rapidly. During preliminary investigations, AEOI engineers had also identified a second possible site for a nuclear power plant at Darkhovin, 40km north of Ahvaz city, less subject to earthquakes and also close to an abundant water source, the Karoon River. This was where France would come in. In June 1974, a preliminary agreement for the supply of two 900MW reactors (the first to be operational in 1982 and the second in 1983), some Uranium and a nuclear research center to Iran was signed between AEOI, Framatome and CEA (Commissariat à l'Energie Atomique).

In 1979 after Iranian revolution followed by Iran-Iraq 8-year war, nuclear programs and all related projects were abandoned for almost 10 years. In 90s the Iranian government and AEOI revised the nuclear program of the country and firmly decided to promote this technology and also boost the domestic research and development in energy sector, particularly nuclear power. Booshehr I reactor finally commissioned in the end of 2010 by AEOI in collaboration with Minatom (Ministry of Atomic Energy for the Russian Federation). Apart from Booshehr reactor many other nuclear facilities (mostly related to fuel cycle) have been developed by AEOI's scientists and engineers. Uranium Mining and Milling facilities in Saghand, Conversion and Fuel Fabrication facilities in Isfahan and Enrichment unit in Natanz are some of the most advanced nuclear power related facilities constructed since then.

**Chapter 4: “Energy Pricing and Policy Recommendations”**

## **Résumé**

Les subventions aux combustibles fossiles ont été mises en œuvre dans de nombreux pays producteurs de pétrole et de gaz depuis les premières exploitations de réserves d'hydrocarbures. Ces subventions sont les principaux obstacles entravant le développement d'un parc national optimal de production d'électricité, car ils favorisent le maintien d'une part significative de combustibles fossiles dans le mix énergétique. Nos modèles d'optimisation utilisés au cours des chapitres précédents nous aident à identifier les méthodologies de tarification de l'électricité les plus optimales, basées sur le principe de l'optimisation des coûts d'opportunité.

Les prix optimaux de l'électricité, égaux aux coûts marginaux de long terme, résultant de nos modèles, sont très éloignés des tarifs domestiques effectivement appliqués aux consommateurs finaux. Les politiques énergétiques optimales ainsi que les stratégies de réforme efficaces sont proposées. Une réduction progressive des subventions et finalement l'élimination de celles-ci, est proposée en conformité avec la structure socio-économique de chaque pays.

Mots-clés: Tarification de l'énergie; Subventions; Politique énergétique

## **Abstract**

Subsidies on fossil fuels, has been implemented in many oil and gas producing countries since the beginning of the hydrocarbon reserve discovery. These subsidies are the main barriers in front of the development of an optimal national generation mix of electricity, as they bias the energy mix in favour of more fossil fuel integration. Our optimization models used in previous chapters help us to identify the most optimal electricity pricing methodologies based on opportunity cost optimization principle.

Optimal electricity prices, equal to long run marginal costs, resulted from our models are far beyond the real domestic end-user tariffs of electricity. Optimal energy policies in parallel with effective reform strategies are proposed. A gradual subsidy reduction and eventually removal, is suggested in accordance with each country's socio-economic structure.

Keywords: Energy pricing; Subsidies; Energy policy

## **Introduction**

In this chapter, we go through various energy pricing policies adapted to oil and gas producing countries. Moreover, subsidies implemented in each country are analysed and some proposals for their reduction and eventually their total removal are offered.

We saw in the case of Saudi Arabia, going toward less fossil-fuel dependent generation mix can save around 3.5 billion dollars per year for the government during 10 years of power production and even more than 5.5 billion dollars per year for period of 20 consecutive years. At the same time, very aggressive renewable scenario without integrating nuclear power units can generate a spin-off effect and increase the generating costs. This impact is mainly due to the instability of power network because of the still high investment costs of renewable technologies and their intermittency. The intermittence nature of these renewables must be damped by back-up units which include mainly gas turbines with very short ramping time. For the case of Egypt, our model's result suggested a progressive integration of non-fossil power units in the future electricity mix of the country. Even for very high discount rates, model showed the benefits of investment in non-fossil resources along with natural gas units. This is true from both short-term and long-term investment planning point of view. And lastly in the case of Iran, we saw how beneficial would be for the national electric portfolio, if Iran invest further in non-fossil power units. Iran can reduce its total risk and cost of power generation, respectively by almost 30 and 20 per cents, through more investment in both nuclear and renewable sources.

Neither Iran nor Egypt nor Saudi Arabia, won't be able to properly promote the incentives for non-fossil power units investments if the intensive energy products subsidies continue to stay in place. Heavy subsidies on fossil fuels make any sort of non-fossil unit uncompetitive compare to fossil-based units.

Subsidies are very important issues in all the three countries that are analysed in this work. They are the most influential drivers behind the abusive (from economic point of view of course) usage of hydrocarbons in the power generation sector. Hereby, we attempt to analyse the impact of these subsidies in the energy economy of our three countries and give some recommendations for envisaged reforms.

### Economic Evaluation of Energy Subsidies

Energy subsidies arise when the price paid by consumers is below a reference price, in our case the export price of the energy commodity. For wholesale market consumers subsidies (before-tax) the reference price is taken as the supply cost, whereas for retail market consumers subsidies (after-tax) the reference price is the supply cost plus a consumption tax to contribute to revenue objective like any other good such as the value added tax (Coady et al. 2015). Of course in an environmentally efficient system the Pigouvian tax for internalizing environmental externalities should be added to this reference price for post-tax consumers' subsidies. In figure 4-1 we show these notions of energy subsidies for a single energy commodity.  $P_s$ ,  $P_e$  and  $P_c$  are respectively denote supply cost, consumer price and the efficient price of the energy commodity for an energy consumption of  $Q_c$ . blue box indicates the before-tax consumer subsidy which is equal to energy consumption times the difference between supply and consumer price. The after-tax consumer subsidy equals the sum of the two gray and blue boxes, equals energy consumption multiplied by the difference between efficient and consumer (retail) prices of the energy product. This excess cost of subsidy is either provided by the governments in form of budgetary support or too simply forgone revenues.

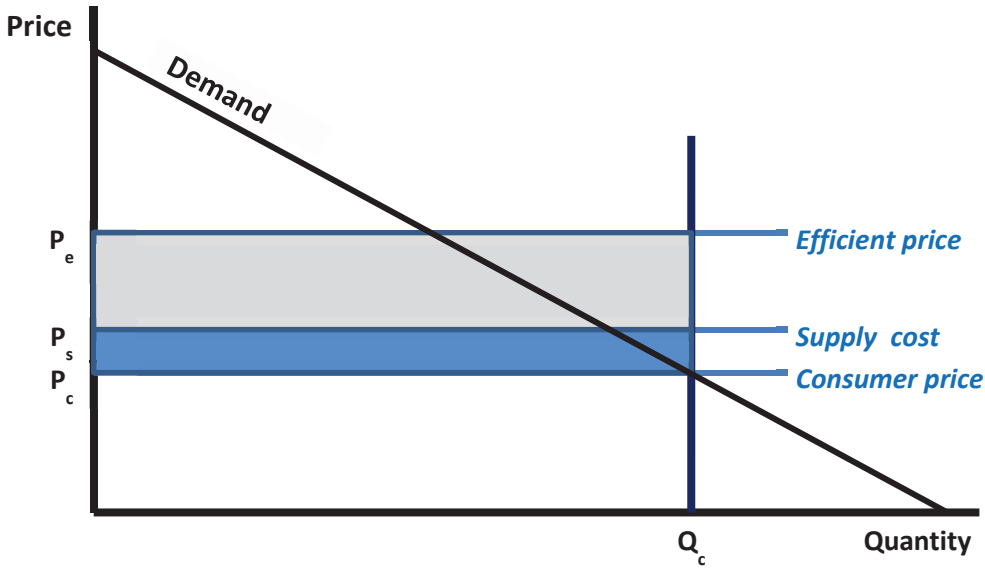


Figure 4-1

In addition to consumer subsidies, there is also another form of subsidy existing in Saudi Arabia, Egypt and Iran, called producer subsidy. It exists when electricity producers receive either direct or indirect supports from the government that raises the profitability above what it otherwise would be. This can take various forms, such as receiving a price for the output above the generation cost or even receiving a direct transfer from the budget.

Applying subsidies reform can bring fiscal benefits consist of the before-tax consumer subsidy and the revenue generated from increasing the price above the supply cost with the tax base reduced to efficient production  $Q_e$ . Welfare gains from subsidy reform are indicated by the red and yellow triangles in figure 4-2.

In general:

$$Fiscal\ impact = (P_e - P_s) Q_e - (P_c - P_s) Q_c$$

And

$$Welfare\ gain = (P_e - P_c) Q_c - \int_{P_c}^{P_e} Q(p) dp$$

Last but not the least, we should mention that the efficient price of energy commodity ( $P_e$ ) could be equal to international reference prices or reference prices plus the environmental cost of energy consumption and other externalities.

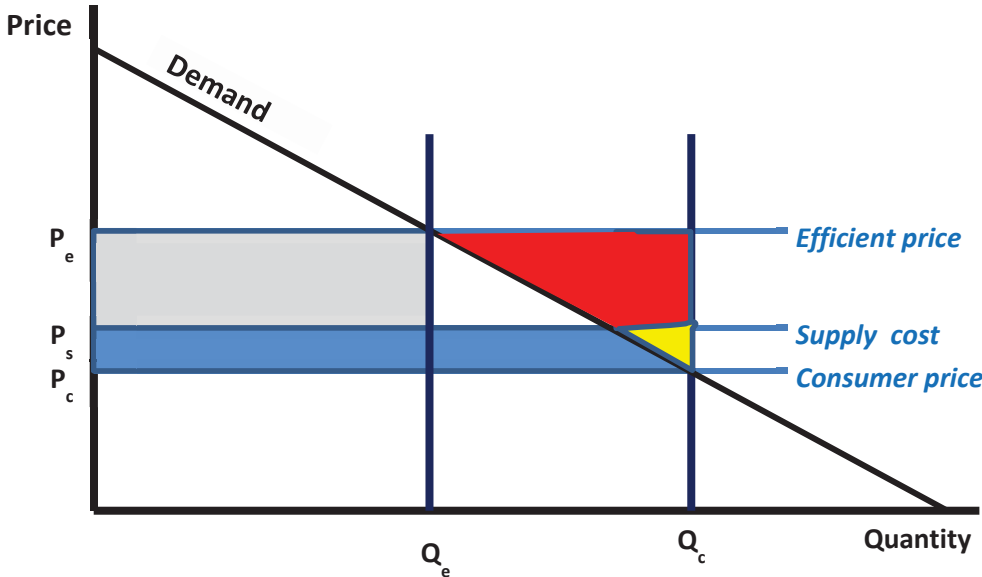


Figure 4-2



Subsidies to fossil fuels remain a big challenge in spite of many efforts from Egyptian, Saudi and Iran's governments to reduce or eliminate them. Especially where they have become too much of a burden on the public purse. MENA countries, including Egypt, Iran and Saudi Arabia, account for almost half of the total amount for fossil fuel subsidies (IEA 2014). They generally set domestic prices above the cost of production, but well below the prices of those fuels could reach on the international market.

One of the most damaging effects of subsidizing fossil fuels is on clean energy investment; for example in the middle east, more than one-third of electricity is generated using subsidies.

In the absence of subsidies, all of the main renewable energy technologies, as well as nuclear power units, would generally be competitive with oil-fired plants in the Middle East. Our modelling effort in previous chapters confirmed these results. Most countries with large fossil-fuel subsidies recognize the need to eliminate or at least reduce them. But this effort often faces with too many difficulties coming from strong resistance of those consumers and producers that stand to lose the most. Experience showed that some basic principles must be followed for reforming subsidies. The starting point should be to get pricing right and ensure that energy prices reflect their full economic value by introducing market pricing and remove price controls. Figure 4-3 shows the value of fossil fuel subsidies in different countries in 2013 (WEO 2014).

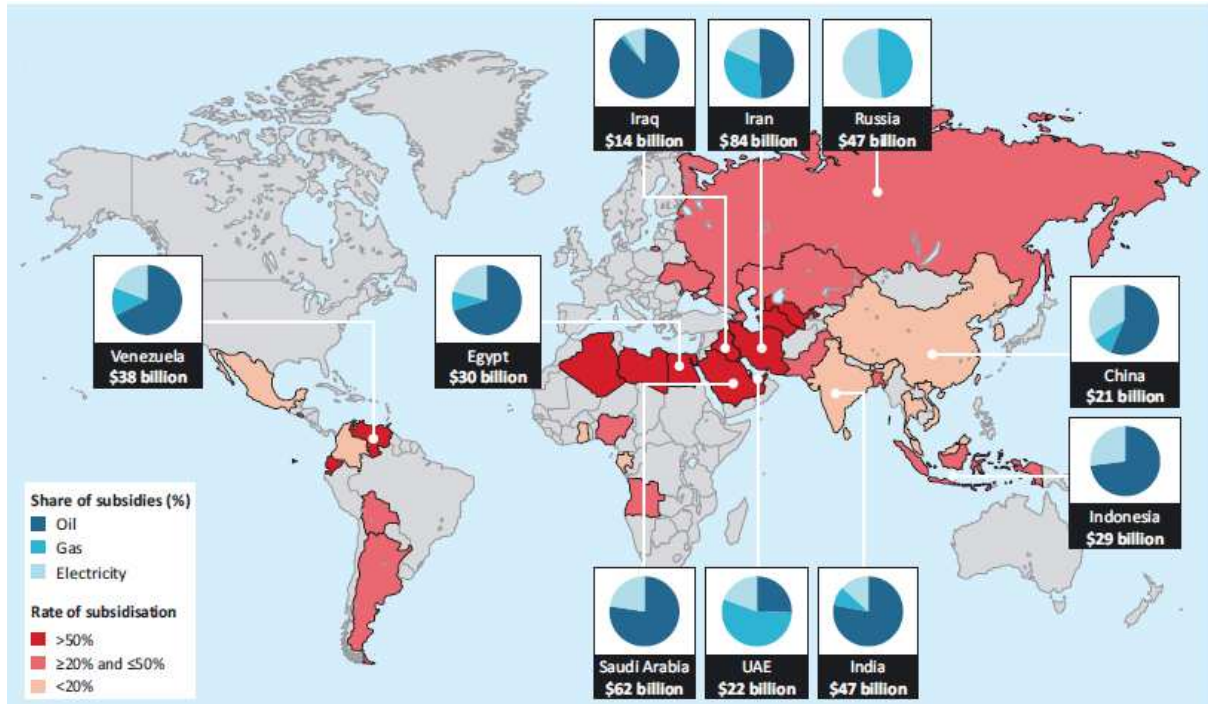


Figure 4-3

As we can see in the figure 4-3 that Iran stays in first place with around 84 billion dollars of subsidies and also their amount as share of GDP and rate (figure 4-4) .

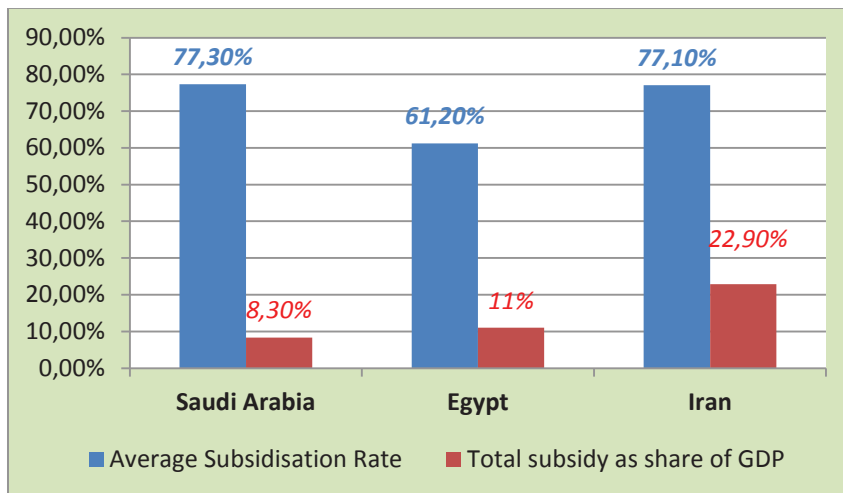


Figure 4-4

(Source: IMF 2014)

While when it comes to the value of subsidy per head, Saudi Arabia is by far in the first place among MENA region's countries (figure 4-5).



Figure 4-5  
(Source: IEA 2014)

And if we look at the detailed energy fuel subsidies of these countries (figure 4-6), we observe that in both Iran and Saudi Arabia the total amount of energy subsidies has been increased since 2011, while this amount is constant for Egypt. This is not the case for electricity subsidies. Iranian electricity subsidies have decreased by around 20% between 2011 and 2013. To lesser extent, the same trend is observable in case of Saudi Arabia with 5% of reduction in electricity subsidies. However, Egypt followed the opposite direction and experienced an increase of 14% in electricity subsidies while the total amount of energy subsidies (oil, gas, coal and power) remained almost constant.

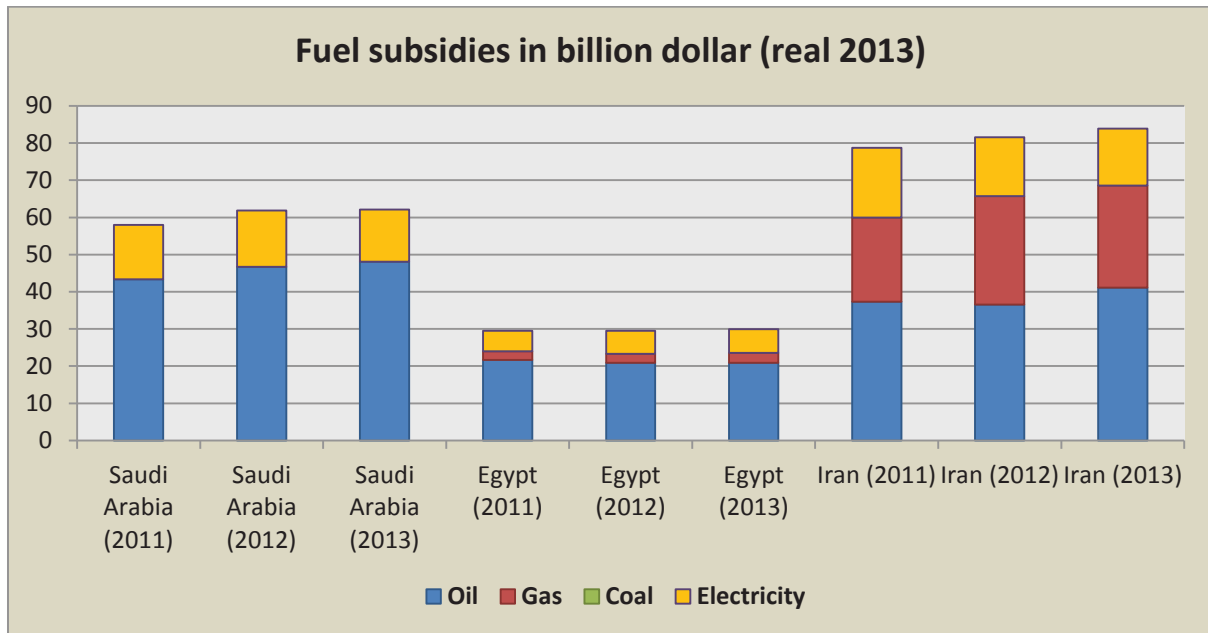


Figure 4-6

(Source: IEA 2014)

Saudi Arabia, which has among the fastest rates of growth in electricity demand in the region, is also seeking to diversify away from oil-fired generation to natural gas, nuclear and renewables. It has announced measures to boost the deployment of renewables to compensate from their lack of competitiveness against both oil and gas fired power plants. Oil supplied to domestic power stations is priced at just 4.4 USD/b (around 5% of its international market value) and gas is just 0.75 USD/Mbtu (7% of current European prices). In 2012, the Saudi government announced plans to build 41GW of solar (both PV and CSP) by 2032 as well as to develop wind and nuclear power (16 reactors) over the next two decades. The quantified benefits of all these efforts were clearly showed in the first chapter of this work.

One of the central ways to reform the electricity sector in Saudi Arabia is to ensure that electricity wholesale and retail prices reflect total cost of power generation. Like many oil-producing countries, Saudi Arabia implemented heavy subsidies on fossil fuels to alleviate poverty by making energy economically accessible to the poor. Keeping energy tariffs low has also been used by Saudi Arabia as a tool for managing inflation. But this policy leads to a considerable dead-weight welfare loss for the country. Saudi government lost revenue

because of subsidies (instead of having exports revenue) is far greater than the rise in national consumers’ surplus. Furthermore, by keeping the end-users prices low, fossil fuel subsidies promote over usage of energy and high fossil fuel consumption growth rate. Currently Saudi Arabia charges only 5 USD/bbl domestic consumers which is 20 times lower than the observed average price of crude oil (between 2011-2014) in the international market (Table 4-1).

<b>Heavy fuel oil</b>	<b>0.43</b>
<b>Natural gas</b>	<b>0.75</b>
<b>Diesel</b>	<b>0.67</b>
<b>Crude oil</b>	<b>0.73</b>

Table 4-1 : Fuel price for electricity producers in USD/MMbtu

(source: ECRA 2014)

Obviously, these prices are very low for encouraging investment in non-fossil fuelled power plants and deploying energy efficiency measures. While low domestic natural gas prices helped to develop the petrochemical sector of Saudi Arabia (constructing more than 20 complexes compare to 1 in 1983), it has not been created suitable incentives for investments in the development of natural gas fields and related processing and transport facilities for bringing it to market. Table 4-2 shows the electricity tariffs in Saudi Arabia for various categories of consumers in US dollar.

<b>Consumption in kWh</b>	<b>Residential</b>	<b>Commercial</b>
<b>1-2000</b>	0.013	0.032
<b>2001-4000</b>	0.027	0.032
<b>4001-5000</b>	0.032	0.053
<b>5001-6000</b>	0.032	0.053
<b>6001-7000</b>	0.040	0.053
<b>7001-8000</b>	0.053	0.053

<b>8001-9000</b>	0.059	0.069
<b>9001-10000</b>	0.064	0.069
<b>&gt;10000</b>	0.069	0.069

Table 4-2 : Electricity tariffs in Saudi Arabia in USD

(source: SEC 2014)

It is evident that in short term, the upward energy price reform would be very difficult and socially sensitive. Nevertheless, this situation should not halt the idea of increasing the end-user energy prices in the medium and long terms. First step toward this objective could be the rise of inter-sector energy transfer prices. In simple words, raising the prices paid by the power generators, petrochemical units and desalination plants for example. This action can induce higher efficiency and national energy consumption among energy intensive sectors. Currently, there are several inconsistencies preventing the Saudi pricing structure from emitting the right signals to the main energy sector players. For instance, selling price of electricity to the grid from desalination units is fixed in long term contracts, lacking any sort of modulation during the day. Since gas prices for these units are fixed (as well as that of the water produced) there is no incentive to use the water plants for peak shaving purpose, thus missing a very cost effective method. For example Matar et al. (2014) showed that increasing inter-sector transfer prices will lead to considerable fuel consumption reduction in the country for almost 5% of Saudi Arabia's yearly GDP.

We should also emphasize on the fact that there is strong need of incentives for more private investment in the Saudi power sector. More competition is needed to increase efficiency and reduce the burden on the public spending. Structure of the Saudi electricity sector was thoroughly developed in chapter 1 of this work. While the transmission and distribution of electricity to final users still falls under the Saudi Electricity Company, the country should gear its power system towards a more competitive power market by planning to restructure SEC into separate independent entities overseeing generation, transmission and distribution. This will lead to the removal of entry barriers for new producers, with the objective of reaching greater efficiency and reducing public spending in the power sector.

In case of Egypt, which is a relatively poor country (compare to Saudi Arabia for example) with a large and rapidly growing population (82 million), energy use has soared in recent years, partly as a result of large subsidies. Egyptian energy demand expanded at an average annual rate of 5.6% over the period between 2000 and 2012. Egypt has recently become a net importer of oil and its natural gas exports have been decreasing because of the rising domestic demand. Power generation capacity has almost failed to keep pace with fast growth of energy demand, leading to frequently happened brown outs and black outs. Up to now, Egypt had made little progress in reducing its large and long-standing energy subsidies. For instance, in 2013, fossil fuel subsidies totalled 30 billion dollars, accounting for 11% of GDP and absorbing almost one-fifth of public spending according to the official budget statements. Oil products have been the most heavily subsidized, with most of the rest going for power generation, mainly by subsidizing natural gas inputs to power plants. Fossil fuels subsidies in Egypt by fuel are illustrated in figure 4-5.

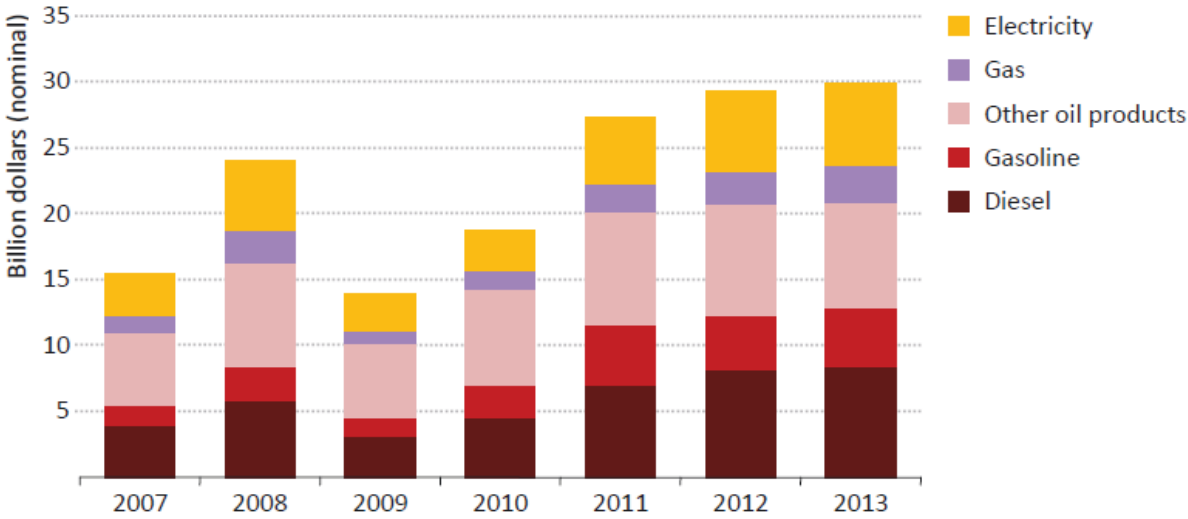


Figure 4-5  
(Source: IEA 2014)

Knowing these problems, Egyptian government have repeatedly announced plans to scale back energy subsidies, but have then tended to backtrack, because of the public opposition.

Between 2005 and 2008, power prices were raised and a mechanism for gradually increasing electricity prices towards market levels implemented. But the financial crisis of 2008-2009 and subsequent political turmoil put on hold any further implementation of reforms.

A renewed effort to reduce energy subsidies has been launched again by the new government in July 2014. In addition, power tariffs for all end-users were raised, as part of a plan reach cost-recovery levels over a five-year period since then. Electricity prices were raised by EGP 0.3 (0.03 USD) per KWh on average, as the first step towards doubling prices and eliminating subsidies within five years. Natural gas prices for range of industries increased by 30% to 70%.

Next, we attempt to analyse the pass through effect of intensive subsidies in the wholesale and retail power tariffs of Egypt. For this purpose, a static cost-minimization model of Egyptian power supply has been constructed for the reference year 2010. In this model demand's variation is based only on the peak/base periods and seasons. Hence neither medium nor long term demand increase scenarios were applied.

The shadow values (marginal values) associated with the loaded power (model's output) for each season and each hour corresponds to the marginal values produced by the last power unit (MWh). Observation of those values for our static model (in reference year 2010) indicates that the marginal cost of electricity production is around 72\$ per MWh. Actually this value is the average of all the marginal values generated by the model for each season and hour of the day. Due to the fact that the technology does not change during peak hours, it can be used as a proper indicator of total marginal cost.

The weighted average of Egyptian electricity tariffs (multiplying the share of each consumer by its related tariffs) is equal to approximately 30\$ per MWh. This value is less than almost 60% of the marginal value given by our optimization model. Hence, if we consider for example the marginal pricing criteria as an optimal way of electricity pricing (in which short-run and long-run marginal costs are equal and future investments are guaranteed), the existing tariffs are far below the optimal level. In other words, the allocated utility of fossil fuels (including subsidies) associated to the power generation is higher than the potential value of these fuels (oil and gas) for a probable export or unsubsidized usages in the power and other



energy intensive sectors. This observation confirms the distorted optimality of the current heavily-subsidized power sector of Egypt, in terms of both fuel prices and final tariffs.

<b>Current Electricity Tariff Structure (1 Pt ≈ 0,14 \$)</b>	
<i>Sector</i>	<i>Average Price (Pt/KWh)</i>
<b>Residential</b>	30
<b>Commercial</b>	40
<b>Agriculture</b>	11
<b>Industry</b>	20

Table 4-3: Egyptian Electricity Tariffs

(Source: WoodMackenzie & EEHC)

Finally in case of Iran the changes were more drastic compare to Saudi Arabia and Egypt. Actually Iran was the first major energy producing and exporting country to cut its energy subsidies with a 'Targeted Subsidy Reform' in December 2010. Iran's Reform Act stipulated that prices should be adjusted to 90% of Persian Gulf price levels within five years, but did not specify the price adjustment path for different products. The Reform Act also stipulated that the reduction in energy subsidies would be replaced with cash transfer payments to the population and that households would receive 50% of the government revenues raised from higher energy prices. The physical distribution of the cash transfers was well planned, starting over a month before price increases were implemented by depositing money in household accounts.

The corporate sector received direct assistance and limited quantities of fuels at somewhat discounted rates to moderate the impact of higher energy prices on operating costs. Corporate support packages include tax reductions and additional credit lines to compensate for lost cash flow from higher operating expenses as well as interest subsidies on loans for implementing energy saving technologies to reduce energy intensity. It is estimated that the price increases removed about US\$ 50-60 billion in annual product subsidies from the Iranian government budget.

The following price increases were introduced in December 2010 for the main energy sources as part of the subsidy reform:

Gasoline: prices increased from 10¢ per litre (when using up to 60 litres) or 40¢ per litre (when using more than 60 litres) to 40¢ per litre (for up to 60 litres) and 70¢ per litre (for above the 60 litres).

Gasoil: prices rose from 1.5¢ per litre to 15¢ per litre (for subsidised quota) and 35¢ per litre for volumes purchased on the open market.

Kerosene: prices rose from 1.5¢ per litre to 10¢ per litre and fell 50% in the first ten days, mainly in the household sector

Natural gas: price increased from 1.3¢ per m<sup>3</sup> to 7¢ per m<sup>3</sup> for households and from 0.5¢ per m<sup>3</sup> to 8¢ per m<sup>3</sup> for power plants.

Electricity: prices rose from 1.7¢ per kWh to 4.5¢ per kWh for households and 4¢ per kWh for industry.

Compressed Natural Gas (CNG): prices rose from 4¢ per litre to 30¢ per litre

While Iran intends to further remove energy subsidies over the next years, we believe this will be difficult to achieve as inflation levels have already soared over the past two years in response to tightening sanctions. Additional energy price increases (albeit partly compensated by cash reimbursements from the government) would only accelerate inflationary pressures at a time when domestic consumption is already weak and the Iranian economy is in recession. Instead, the new government will first want to stir the economy out of recession and back to economic growth to avoid social unrest. Furthermore, it is not clear whether the new Rouhani government intends to continue the previous government's policy of compensating subsidy removals with cash hand-outs as some economists have argued that the cost of cash payments have already exceeded the former cost of subsidies. Besides, the effect of these increases on the prices of energy has been largely offset by the sharp drop in the local currency, which has increased the gap between domestic prices and the international value of the fuel.

## **Implementing Market and Subsidy Reforms**

The main objective of policy makers to reform fossil-fuel subsidies is to get right prices in a way that energy prices reflect their true economic value. This can happen by letting the market determine pre-tax prices freely in competitive and efficient markets. However, it is not advised to introduce market pricing of fossil fuels very suddenly. This would not only lead to political problems but also to a sudden and sharp rise in prices, as well as short-term price volatility. Introduction of a formula-based automatic pricing mechanism, which ensures that retail prices reflect variations in international prices, could be a very practical approach. Such mechanism can assist in progressive transition to full market pricing system. The frequency of price adjustment can prepare the consumers to face with small price movements likely to be experienced in a competitive market. However, we should not forget that this process should be realized in an entirely transparent manner helping to depoliticise energy price-setting.

This reform must be in paralleled with energy sector restructuring. This may require breaking up historical state-owned companies, facilitating third party access to infrastructure (e.g. power grids) and the entry of new players. Once retail prices have reached international levels and the national market has been formed in a way that permits effective competition in both wholesale and retail parts of the business, the state can abandon the administered mechanism and let the market freely determine prices. This should be done alongside with fiscal reforms aimed at achieving a rational tax structure. The best way to see when we have arrived sufficient competitiveness in the energy market is to put price ceilings. Contrary to fixing prices, price ceilings gauge perfectly the market competitiveness in the sense that when prices fall below ceilings and they starts to vary among companies, this can be considered as a reliable sign of emerging competition (Kojima 2013).

Obviously it is very difficult to make reform with the presence of those who benefit from subsidies. They will always have an interest in defending subsidies when their gain goes beyond their share of the economic and environmental costs. Under some circumstances the removal of subsidies could become extremely difficult. This was the case of Egypt for example that an attempt to reduce heavy subsidies on gasoline led to strong public reluctance. The longer the subsidies have existed, the more reluctant the opposition to remove them. Particularly if energy-intensive technologies gradually adopted by the beneficiaries. At the same time, their situation is understandable and it is better and easier to get them involved in

the reform process to benefit from their experience and knowhow and to ensure that the compensatory measures answer adequately to their concerns.

Energy price reform in Iran in 2010 is a good example of the above mentioned strategy. Increases in oil, gas and electricity prices were accompanied by compensatory cash payments to poor households. This allows making sure that the benefits are not skewed towards the richest ones and encourages more efficient energy use. Furthermore, cash in hands of consumers can increase consumer spending or savings, which in either case, can boost the economy to some extent.

This could be a very good temporary measure and if more permanent support is necessary, other measures in social actions, health system, education and even direct welfare payments to the poor, could be implemented.

Beaton et al. (2013), explain that in reality a mixture of what is practical, politically feasible and can answer to both consumer and producer preferences must be adopted.

Lastly, it is vital to communicate the benefits of reforms to the population. This can be very difficult task. In oil producing countries, in our case Saudi Arabia, Egypt and Iran, persuading the nation that oil and oil-products must be domestically priced at their opportunity cost and not their production cost can be extremely difficult. This can become even more challenging when the revenue from export of these resources is not shared by the population at large.

In many cases, the public is not to be automatically convinced by government promises to redirect spending to other 100% public services. Hence, careful communication strategies must be in the agenda of all relevant agencies. The success of Iran's energy subsidy reforms was substantially aided by a very effective public relations campaign.

### **Energy Pricing Policies Analysis**

In general, energy prices are not really of the best tools for energy resource and demand management. The objectives that governments must try to achieve through their pricing policy can be found in Munasinghe (1980), Schramm (1983) and Bathia (1990) and with more theoretical discussions in Drèze and Marchant (1976), Bös (1985), Brown and Sibley

(1986) and Berg and Tschirhart (1988). In this section we discuss only the main concepts and objectives within which we will analyse the optimality of the energy (power sector) pricing system of studied producing countries.

The first objective of energy pricing is to attain an economically efficient pricing system. This promotes economic growth through efficient allocation of resources within the energy sector, and between the energy sector and the rest of the economy. Efficient and optimal energy use implies that the price for a marginal unit of energy is equal to the economic cost of providing that unit. Hence, the major question is: what are the real economic costs of supplying energy?

The second objective is the promotion of social equity. In the other words, government tries to improve the situation of the poor through the adjustment of energy prices. Such a policy becomes possible only if the demand categories can be separated (possibility of price discrimination). Otherwise subsidized customers can sell the cheap fuel to the other customers. In the case of possible demand discrimination, as long as the price per demand category is below their willingness to pay and above the economic cost of supply, the solution will be optimal from a pure economic point of view.

The third objective is financial and fiscal resource mobilization which concerns mainly the fossil fuel pricing. So as to achieve financial resource mobilization a government will maximize foreign exchange earnings through export or import substitution of energy sources in pure form like oil, coal and gas or transformed form like, fertilizer, methanol and etc. fiscal resource mobilization is achieved by allowing producers and distributors of energy to recover their costs and to earn sufficiently in order to be able to finance their growth and development, but to tax away any extra profits.

And the last objective is the use of energy resources in a sustainable and environmental friendly manner. Because some fuel sources for power pollute more than the others, in this case fuel substitution based on energy pricing policies could be very effective.

The theory of marginal pricing is in line with the theory of pricing public goods in general. According to this theory, economic efficiency is obtained when the marginal willingness to pay (or simply the price) of the last unit consumed is equal to the marginal cost of the last unit supplied which is equal to the economic opportunity cost of the last unit. This sort of pricing

promotes an economically efficient allocation of resources, both within and outside the energy sector (Munasinghe 1980; Munasinghe and Schramm 1983; Brown and Sibley 1986). For utilities that require massive and undividable investments, the World Bank strongly suggests prices based on the long-run marginal cost rather than short-run ones (Schramm 1991). Nevertheless, some economists refuse the use of long-term marginal costs and argue that it is much more plausible to use short-term marginal costs because the investment costs (capital costs) must be considered as sunk costs (Anderson and Bohman 1985).

Under the traditional neo-classical assumptions of a perfectly competitive market it is not difficult to prove the equality of long and short run marginal costs (Cohen and Cyret 1981). This can be done under the assumption that capacity can change continuously and future demand can be forecasted perfectly. These assumptions, however, are not met by the energy sector where indivisibility, irreversibility and durability of investments exist. Therefore pricing in accordance to the long-run marginal costs cannot be valid or applicable (Anderson and Bohman 1985).

Discussions about marginal pricing were somehow pioneered by the famous article of Boiteux in 1949 on electricity pricing and the management of public monopolies. In his article, Boiteux formulated a strategy for electricity pricing based on two separate demand curves, peak and off-peak (base load). He showed that the equality between short run and long run marginal costs holds in case of optimal investment policy. He explicitly stated that “Whatever the capacity of the existing plant, the need to keep prices steady generally leads prices to be fixed as if the plant were of optimum size”. Therefore the price must equal the long run cost when the sector is expanding and future investments need to be planned.

Furthermore, overcapacity in an energy infrastructure is usually required to meet exceptional peak demands. The cost of this overcapacity has to be recovered and cannot be charged only when those exceptional peaks really happen.

Moreover, anticipation of future demand automatically leads to investments with overcapacity because in case of lumpy investments overcapacity often implies lower overall investment costs in the long run. Prices should then be fixed at development costs to make solid capacity development possible. Boiteux’s conclusions are partly the result of the assumption that a utility has a capacity that cannot be expanded easily. In case of large investments and

relatively small marginal operating costs (as in the case of thermal power plants) the theoretical equality between short run and long run marginal costs can be reached when the plant's production is equal to or exceeds its optimal capacity. The cause is the rigidity in capacity implying an infinite derivative of the cost curve once demand goes beyond the installed capacity.

The short run versus long run marginal pricing was also discussed by Williamson (1966). He argued that under the assumption of indivisible investments and a monopoly that maximizes the net welfare gain, the decision to invest in extra capacity is positive whenever the net welfare gain is also positive. Thus the optimal price of energy must be equal to the short run costs when the capacity constraints are not binding and equal to the long run costs plus shadow price (scarcity rent) when they are binding.

Note that both Williamson and Boiteux agree that for an existing power plant the short run cost plus scarcity rent is the first best solution. Boiteux however seeks a solution to a different problem, namely the price that allows undisrupted long term planning of the utility. The price that take this planning (ex-ante demand) into account is of-course the long run marginal cost and the short run cost can never ever guide the investment policy in a growing economy.

Munasinghe and Schramm arrive at the same conclusion by stating that the use of short run cost becomes appropriate only under the static or declining demand structure which almost never happens in energy industry and particularly in the growing countries. Schramm (1991) argues that both short run and long run marginal cost systems are incorrect concepts when it comes into economic efficiency.

Defender of these concepts base their arguments on a partial equilibrium analysis without taking into account the effects on the rest of the economy. In the absence of price discrimination, prices for all consumers are set equal to one marginal cost. At this moment, the utility operates either at a loss or a profit according to status of its marginal costs compare to its average costs. If the marginal costs of adding new facilities increase, then the consumers who in past have paid for the existing facilities now have to pay a higher price. If there are decreasing marginal costs, the older facilities have to be closed down or subsidized. It is not very clear whether this subsidy is efficient or not, given unknown social cost of

capital and marginal net income gains. That issue can be clarified only within the framework of a complete long term general equilibrium model.

Schramm argues that wrong conclusions in the marginal costs debate is not because of the fact that marginal cost concept is incorrect but because it is incorrectly applied. In case of growing demand consumers pay for the future rather than historical costs. These marginal costs will cover not only the current running costs but also cost of future additions to the system for a reasonable planning horizon and the replacement cost of existing system. In reality Schramm goes even one step further and states that ideally additional demand must pay for the marginal or additional cost. The main problem with his proposal is as in all the other long run planning systems: what is reasonable planning period and how can reliable data for the future demand be obtained? It seems that, like Boiteux, Schramm attempts to achieve two main goals: economic efficiency and mixing new project efficiently into the existing situation. The result of his rule is the avoidance of sharp fluctuations and volatility in prices and a minimization of spill-over effects to other sectors of the economy.

Now let's conclude from the above discussion about the correct ways of marginal pricing. Differences in opinions come from two factors: considered time period and the investments context, that means one isolated investment at a time versus a specific investment in relation to all previous and planned investments. Everybody agrees that if a system has long run spare capacity, the price to charge for this capacity can temporarily be less than the long run marginal cost. Nevertheless, if this price reduction does not promote any sort of demand increase, it is not necessary to lower the price.

The main concern of the supporters of prices based on the long run marginal cost is the long term development of an optimally planned system in a growing economy. In this case, long run marginal cost seems more efficient and optimal than the short run one, and seems to better account for the spin-offs to other sectors of the economy. As a matter of fact the economically efficient solution can be found only in a complete model of economy, but such a model is not available and is very difficult to construct (Dervis, Martin and Wijnbergen 1985).

For a growing economy, the long run concept seems the most appropriate one but still the main question is how to estimate this marginal cost. Note that Munasinghe and Warlord (1982), and Munasinghe and Schramm (1983) also tend to interpret the fixed charge in the



long run marginal cost as the price for the future economic resources and not as a compensation for historical or sunk cost. Another argument in favour of the long run marginal cost pricing is the practical difficulty of determining the correct short run marginal cost plus scarcity rent that will adequate short run supply and demand. In practice there is no time to iterate and converge towards equilibrium. The need for the public utility to cover its own expenses is also an argument in favour of the long run concept. Actually, with the prices set at long run marginal cost, positive financial benefits for such a utility are very likely, but of course not guaranteed. It lets the utility to break even or make profit which will be led to relatively stable prices and long-term economic efficiency.

## Conclusion

Consequently, in this work we went through the long-run marginal cost in order to make our pricing optimization in different countries. As a matter of fact, for each country, long run marginal cost calculated (based on the optimization model's result for each country and each time horizon) and compared to the existing tariffs of the power sector.

As explicitly explained in previous chapters, each model has been chosen according to the specificities of the national political economy adopted in the analysed countries. For instance, no CO<sub>2</sub> costs were considered in the optimization model of Saudi Arabia as there is no sign or message of CO<sub>2</sub> costs integration into the national energy system. If that happens, CO<sub>2</sub> costs would dramatically push the electricity tariffs farther than optimal values. This is not the case neither in Egypt nor in Iran for which CO<sub>2</sub>-integrated models were adopted for national power system optimization. Moreover, we observed the very high sensitivity of optimal solutions to the energy commodity prices. Obviously, this is also the case for dual values of the optimization models equal to optimal electricity tariffs. Consequently, changes in oil price in the international markets would intensely impact the results. In line with our calculations, oil price drop down to 30 \$ per barrel can highly damage the benefits of optimal pricing in our oil producing countries. This is true from both economic and political perspective. At the same time, any gradual oil price escalation ending to price stabilisation around 80 \$ per barrel in the medium and long terms would be a very decent opportunity for the governments to start to adopt a rational economic politic towards total removal of energy subsidies. This could be done by increasing the final prices of energy in parallel and proportional to the oil and gas prices upward movements. The more constant and gradual growth of oil and gas prices in the international and subsequently national markets, would make it easier and politically acceptable for the governments to implement the optimal pricing regimes without any sort of subsidization.

Finally we should emphasize again on the fact that all of the presented pricing concepts have been analysed under the assumption of neoclassical-perfectly-competitive market condition. Hence, any difference between the studied countries' existing-tariffs and the optimal tariffs, calculated from the model for the long-run marginal costs of power generation, does not necessarily mean that the system is not optimal. At the end of the game, it is the role of the

regulator to choose the most adapted and optimal way of pricing for its system in accordance with the country's specific economic philosophy and social structure.

## General Conclusion

Through all this work, our main attempt was to propose the most optimal way of electricity generation in oil and gas producing countries. This happened under various simulation and optimization modelling approaches. Current and future power generation mixes of each country were analysed through our models and finally recommendations regarding the economic and energy policy were suggested based on the obtained results in each model.

Our linear programming model of Saudi Arabian electricity production showed us how inefficient is the power system of the country in terms of the utilisation of non-fossil resources. According to our model's results, Saudi Arabia can easily attain 29% of total generation cost reduction by 2020 if the country manages to integrate up to 50% of non-fossil electric power into its electricity generation mix. A mixture of both nuclear and renewables would be the most optimal strategy for tackling this objective. And by keeping 30% share of renewables in the national electricity mix, Saudi Arabia can benefit a yearly cost reduction of 3% over the 2020-2030 periods.

Moreover, 100% fossil-based power generation structure of the Saudi Arabia, consumes around one third of total oil consumption of the country. Under the forecasted demands' scenarios for 2020 and 2030, the total oil consumption of Saudi Arabia for electricity demand satisfaction will reach respectively 1.5 and 2.25 million barrels per day. This can be even more if the share of fuel power plants becomes higher than the current one equals to 55%.

In line with the model's result, not only Saudi Arabia can benefit from considerable cost reductions, but could also release a non-negligible amount of crude oil for export. For example, under the 50% non-fossil scenario, the country would be able to release up to 500,000 barrels per day for export in 2020 and completely satisfy its power generation demand.

Finally, Saudi Arabia must envisage a dramatic reform in its subsidization policy for fossil fuels and energy products in general. Currently, Saudi Arabia charges 5 dollars per barrel the domestic oil consumers. This amount is at least 10 times lower than the current price of crude oil in the international markets. Such an aggressive subsidization policy, leading to very low electricity tariffs, will avoid the proper implementation of incentives for investments in non-

fossil power units. Hence, in the medium term, a gradual upward energy price reform is vital for having an optimal power generation mix.

The non-fossilization of national generation mix is so economically beneficial for Saudi Arabia that we did not perform any sensitivity analysis over the CO<sub>2</sub> price. Compare to the above-mentioned benefits, the impact of CO<sub>2</sub> price variation is very negligible and meaningless. However, we should not forget that the decarbonisation process of the generation mix will provide both financial and of course environmental benefits.

Egyptian power generation mix optimization process was done under the dynamic linear programming approach so as to better integrate the effects of high uncertainties existing in Egypt. Moreover, smoother and more gradual (step-by-step) investment trends could be achieved in this model.

The optimization model results showed that for the low discount rates over the period of 20 years, nuclear power is the most efficient and economical way of electricity generation for future electricity demand satisfaction of the country. More investments in nuclear units becomes even more rational if the current electricity market structure of Egypt remains intact over the next two decades and the government remains very much involved in the energy infrastructure investment. While going towards more privatization of the power industry and consequently higher discount rates, envisaged by the private investors (more short-term financial profit-seeking attitude), fossil power units and particularly combined-cycle-gas-turbine power plants become more economic.

These conclusions obtained under the zero carbon emission price assumption. In fact, implementation of CO<sub>2</sub> price in the model encourages a massive investment in nuclear power units even at discount rates ranged between 8 and 10 per cent.

Other non-fossil resources (wind, hydro and solar) were integrated to the model as fixed parameters. The Egyptian Renewable Energy Expansion Plan adopted in 2008, set a target for these renewable sources to reach 20% of total energy supply by the end of 2020. We assume in our model that this target is certainly achievable within the 20 years' time-frame of our model which means two times more than what has been announced. However, we have

introduced into the model the necessary fossil-fuel power plants that play a back-up role in case of insufficient capacity factors of these renewables.

The economic analysis of the power generation mix with an optimization model and under explained assumptions, pointed out that due to the resource availability and the future expected electricity needs, being mainly dependent on national fossil fuel reserves for power generation is not an economic optimum. The Egyptian gas resources could be exported and more power units could be based on renewable resources or nuclear power plants.

Nevertheless, these choices could be heavily affected by the evolution of costs, demand and carbon prices over the modelled 20-year period. Thus, an investment strategy based on a gradual integration of nuclear and renewables is suggested for the Egyptian electricity generation mix.

Identical to the case of Saudi Arabia, the significant difference between the dual values of our optimal model and the existing energy prices in Egypt shows the heavily subsidized nature of energy sector. Hence, the promotion of nuclear and renewables must be accompanied by the gradual removal of these subsidies.

Finally, the electricity generation mix of Iran were analysed under the Markowitz mean-variance portfolio approach. Total generation cost of electricity was simulated under monte-carlo techniques so as to absorb all the costs uncertainties of various power units, including fossil and non-fossil technologies. Therefore, national electricity generation portfolio of the country was constructed based on the simulation's results and under a cost-minimization optimization model. We produced an efficient frontier of power generation rest on the risks (associated to each specific technology) and cost inter-relationship among generating units.

By comparing the current Iranian electricity generation portfolio with that of the efficient frontier, we realized how non-optimal the current portfolio is. Results indicate us a significant potential of improvement in terms of both costs and risks. They can be reduced by around 15% if the current power generation portfolio of the country contains higher shares of non-fossil power units.

Several scenarios could be envisaged by Iran for reaching the efficient frontier. Scenarios were ranked from less risky to higher risk electricity portfolios according to the national

planner strategy. Whatever the strategy obtained, the share of non-fossils must reach at least up to 30% of the total generation mix with nuclear counts for 20% of this non-fossil share. The least cost strategy encourages even higher share of nuclear power, while other renewables leave their place for natural gas.

What we recommend for Iran in this work, is a medium scenario containing an equally trade-off between risk and cost. On one hand, very aggressive investment strategy for renewables and nuclear can lead to very high technological risks and the latter may also produce important political risks which cannot be easily integrated the optimization models. On the other hand, the current dependency of the Iranian generation mix on the fossil resources can highly damage the optimality and cost-effectiveness of the national electricity generation portfolio.

For Iran we did not perform any modelling with regard to the optimal energy pricing as the government has recently fulfilled several successful actions toward energy subsidies removal. However, the positive economic effects of these reforms were absorbed by consecutive high inflations and exchange rate devaluations of local currency.

Last but not the least, we must mention that in this work the base-case year was 2010 during which time, the average price of crude oil was around 100 dollars per barrel. While as explained in the fuel cost section of previous chapters, we took into account a four-year average price of 80 dollars per barrel for crude oil in our models. Even if the current price of crude oil (Brent) fluctuates around 65 dollars per barrel, we believe that in the medium and long terms our assumption is much closer to long-run average price. Besides, investment planning and strategy in capital-intensive and strategic industries such as electric power generation should rely mainly on long-run or at least medium-run contexts rather than short-run ones.

## Conclusion Générale

Tout au long de ce travail, notre objectif principal fut de proposer un parc optimal pour la production d'électricité dans les pays producteur de gaz naturel et de pétrole. Ceci a été effectué à l'aide de divers modèles de simulation et d'optimisation. Les parcs optimaux de production d'électricité actuels et futurs de chaque pays ont été analysés grâce à nos modèles et enfin des recommandations concernant la politique économique et énergétique ont été suggérées à partir des résultats obtenus dans chaque modèle.

Le modèle de programmation linéaire de la production d'électricité en Arabie Saoudite nous a montré à quel point le système électrique du pays est sous-optimal en termes d'utilisation des ressources non fossiles. D'après les résultats de notre modèle, l'Arabie Saoudite peut facilement atteindre 29% de réduction du coût total de production d'ici 2020 si le pays parvient à intégrer jusqu'à 50% de sources d'énergies non-fossiles dans son mix de production électrique. Un mélange de nucléaire et d'énergies renouvelables serait la stratégie optimale afin d'atteindre cet objectif. Aussi, en maintenant à 30% la part des énergies renouvelables dans le mix électrique national, l'Arabie Saoudite peut bénéficier d'une réduction de coût annuel de 3% sur la période 2020-2030.

En outre, la structure de la production d'électricité 100% d'origine fossile de l'Arabie Saoudite, compte pour environ un tiers de la consommation totale de pétrole du pays. Selon les scénarios de demande pour 2020 et 2030, la consommation totale de pétrole de l'Arabie Saoudite pour la satisfaction de la demande d'électricité devrait atteindre respectivement 1,5 et 2,25 millions de barils par jour. Cela peut être encore plus si la part des centrales à combustible devient supérieure à la part actuelle, qui s'établit à 55%.

En ligne avec le résultat du modèle, non seulement l'Arabie Saoudite peut bénéficier de réductions de coûts considérables, mais pourrait aussi libérer une quantité non négligeable de pétrole brut qu'elle pourrait destiner à l'exportation. Par exemple, dans le scénario non-fossile de 50%, le pays serait en mesure de libérer jusqu'à 500 000 barils par jour pour l'exportation en 2020 et satisfaire complètement les besoins pour sa production d'électricité.

Enfin, l'Arabie Saoudite doit envisager une réforme spectaculaire de sa politique de subventions en faveur des combustibles fossiles et des produits énergétiques en général.



Actuellement, l'Arabie Saoudite facture 5 dollars le baril aux consommateurs domestiques de pétrole. Ce montant est au moins 10 fois plus faible que le prix actuel du pétrole brut sur les marchés internationaux. Une telle politique de subventions massives, conduisant à de très bas tarifs de l'électricité, empêche la mise en œuvre correcte de mesures incitatives pour les investissements dans des unités de production non-fossiles. Ainsi, à moyen terme, une réforme progressive des prix de l'énergie à la hausse est vitale afin de permettre l'établissement d'un parc optimal de production d'électricité.

La « défossilisation » du mix de production électrique national est tellement économiquement avantageux pour l'Arabie Saoudite que nous ne réalisons aucune analyse de sensibilité sur le prix du CO<sub>2</sub>. Comparé aux avantages mentionnés ci-dessus, l'impact de la variation du prix du CO<sub>2</sub> est très négligeable et insignifiant. Cependant, nous ne devons pas oublier que le processus de décarbonisation du mix de production apportera des bénéfices tant financiers qu'environnementaux.

Le processus d'optimisation du mix de production électrique Egyptien a été réalisé par le biais d'une approche dynamique de programmation linéaire, de façon à mieux intégrer les effets des fortes incertitudes existantes en Egypte. En outre, les tendances d'investissement plus lisses et plus graduelles (par étapes successives) ont pu être mieux reflétées par ce modèle.

Les résultats du modèle d'optimisation ont montré que dans le cas d'un faible taux d'actualisation, sur la période de 20 ans, l'énergie nucléaire est l'option la plus efficace et économique pour la production afin de satisfaire la demande en électricité du pays. Des investissements supplémentaires dans les unités nucléaires deviennent encore plus rationnels si la structure actuelle du marché électrique Egyptien reste inchangée au cours des deux prochaines décennies, le gouvernement restant très impliqué dans l'investissement dans les infrastructures d'énergie. En s'orientant vers une plus large privatisation du secteur électrique, et par conséquent des taux d'actualisation plus élevés considérés par les investisseurs privés (s'expliquant par une recherche du profit financier à court-terme), les unités de génération fossiles et notamment les turbines à gaz à cycle combiné deviennent plus compétitives.

Ces conclusions ont été obtenues sous l'hypothèse de prix d'émission de carbone égal à zéro. Ainsi, la mise en œuvre du prix du CO<sub>2</sub> dans le modèle encourage un investissement massif

dans les unités de centrales nucléaires, même avec des taux d'actualisation se situant entre 8 et 10 pour cent.

D'autres ressources non fossiles (éolien, hydraulique et solaire) ont été intégrées au modèle en tant que paramètres donnés. Le plan de développement des énergies renouvelables en Egypte (*Egyptian Renewable Energy Expansion Plan*), adopté en 2008, vise à produire 20% de l'électricité du pays à partir de sources renouvelables d'ici à 2020. Nous supposons que cet objectif est certainement réalisable sur la période de 20 ans de notre modèle, soit 10 ans de plus que l'objectif annoncé. Cependant, nous avons introduit dans le modèle des centrales à combustibles fossiles qui jouent un rôle de back-up en cas de facteurs de charge insuffisants des unités de génération renouvelables.

L'analyse économique du parc électrique Egyptien avec un modèle d'optimisation et sous les hypothèses mentionnées a mis en évidence que, en raison de la disponibilité des ressources et de l'évolution de la demande électrique future, ce parc basé principalement sur des réserves nationales de combustibles fossiles pour la production d'électricité est sous-optimal en termes économiques. Les ressources Egyptiennes en gaz naturel pourraient être exportées tandis que plusieurs unités de production à partir de ressources renouvelables ou nucléaire pourraient prendre le relais.

Néanmoins, ces choix pourraient être fortement affectés par l'évolution des coûts, la demande ainsi que par le prix du carbone au cours de la période de 20 ans modélisée. Ainsi, une stratégie d'investissement basée sur une intégration progressive de l'énergie nucléaire et des énergies renouvelables est suggérée pour le parc électrique en Egypte.

Tout comme dans le cas de l'Arabie Saoudite, la différence significative entre les valeurs duales de notre modèle optimal et les prix de l'énergie existants en Egypte révèle la nature fortement subventionnée du secteur énergétique. Par conséquent, la promotion de l'énergie nucléaire et des énergies renouvelables doit être accompagnée d'une élimination progressive de ces subventions.

Enfin, le parc de production d'électricité de l'Iran a été analysé grâce à l'approche de « moyenne-variance » de la théorie du portefeuille de Markowitz. Le coût total de la production d'électricité a été simulé à l'aide des techniques de Monte-Carlo afin de prendre en

compte toutes les incertitudes de coûts des diverses unités de production, à la fois pour les technologies fossiles et non fossiles. Par conséquent, le portefeuille national de production d'électricité du pays a été construit dans un modèle d'optimisation (minimisation des coûts) sur la base des résultats de la simulation. Nous avons produit une frontière efficace de production d'électricité basée sur les risques (associés à chaque technologie spécifique) et les coûts entre les unités de production.

En comparant le portefeuille actuel de production d'électricité Iranien avec ceux de la frontière efficiente, nous avons réalisé à quel point le portefeuille actuel est sous-optimal. Les résultats nous indiquent un potentiel d'amélioration significatif en termes de coûts et de risques. Ils peuvent être réduits d'environ 15% si le portefeuille actuel de la production d'électricité du pays incorpore une part plus élevée d'unités électriques non-fossiles.

Plusieurs scénarios peuvent être envisagés par l'Iran pour atteindre la frontière efficiente. Les scénarios ont été classés du moins risqué au plus risqué des portefeuilles de génération d'électricité conformément à la stratégie de la planification nationale. Quelle que soit la stratégie obtenue, la part des non-fossiles doit atteindre au moins 30% de la production électrique totale avec 20% de cette part non-fossile à partir de nucléaire. La stratégie la moins coûteuse, encourage une part encore plus élevée d'énergie nucléaire, tandis que les énergies renouvelables laissent leur place au gaz naturel.

Ce que nous recommandons pour l'Iran à partir de ce travail, est un scénario médian avec un compromis équilibré entre le risque (50%) et le coût (50%). D'une part, une stratégie d'investissement très agressive pour les énergies renouvelables et le nucléaire peut entraîner des risques technologiques très élevés et peut en outre induire des risques politiques importants qui ne peuvent être facilement intégrés aux modèles d'optimisation. D'autre part, la dépendance actuelle de la production Iranienne aux ressources fossiles peut fortement affecter l'optimalité et ainsi la rentabilité du portefeuille national de production d'électricité.

Dans le cas de l'Iran, nous ne réalisons pas une modélisation à l'égard de la tarification optimale de l'énergie car le gouvernement a récemment accompli plusieurs actions réussies vers l'élimination des subventions à destination des produits énergétiques. Cependant, les effets économiques positifs de ces réformes ont été absorbés par plusieurs épisodes

d'hyperinflation consécutifs et les multiples dévaluations du taux de change de la monnaie locale.

En dernier lieu, nous devons mentionner que dans cette étude, l'année de base considérée (2010) proposait un prix moyen du pétrole brut d'environ 100 dollars par baril, alors que, comme expliqué dans la section des coûts de fuel dans les chapitres précédents, nous avons pris en compte un prix moyen de 80 dollars le baril sur quatre ans pour le pétrole brut dans nos modèles. Même si le prix actuel du pétrole brut (Brent) fluctue actuellement autour de 65 dollars le baril, nous pensons que notre hypothèse de prix est beaucoup plus proche du prix moyen à long terme. En outre, la planification et la stratégie d'investissement dans les industries capitalistiques et stratégiques telle que la production d'électricité devraient reposer principalement sur une politique moyen/long-terme plutôt que sur une réflexion à court-terme.

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## Micro-Glossary

**Allowed rate of return:** The rate of return on firm's assets set by a regulatory authority.

**Ancillary services:** Technical services, such as operating reserves and voltage control, necessary to support a reliable interconnected transmission system; also known as interconnected operation services.

**Augmented load:** Load plus installed generation capacity that is out of service.

**Average cost:** Total cost divided by the quantity produced, equal to average fixed cost plus average variable cost.

**Bilateral contracts:** Contracts used to make trades between two private parties.

**Bilateral market:** A market in which private parties, generators and loads, trade directly at negotiated prices. Neither an exchange market nor a pool. Trades may be arranged by brokers and dealers.

**Black-start capability:** The ability of the generator to start without taking power from the grid. This allows it to help restart the power system in case of a complete failure.

**Capacity factor:** The ratio of the total energy generated by a generating unit for a specified period to the maximum possible energy it could have generated if operated at its maximum capacity rating for the same specified period.

**Competitive price:** The price that equilibrates supply and demand in a competitive market.

**Correlation:** The covariance of the returns divided by the standard deviation of each return.

**Cost-of-service regulation:** Setting prices so that the regulated firm earns a normal rate of profit.

**Counter flow:** A flow of power in the opposite direction to the predominate flow.

**Customer choice:** The ability of end-users to choose their supplier; also known as retail choice.

**Deadweight loss:** The sum of lost consumer and producer surplus. It represents the loss to the economy (society) of a market failure.

**Discount rate:** The rate used to discount a stream of cash flows; the cost of capital of a stream of cash flows.

**Dispatch:** To operate and control a power system, especially with respect to determining the outputs of the system's generators.

**Efficiency, economic:** For a given technology, the minimum opportunity cost to produce output.

**Efficiency, technical:** For a given technology, the greatest possible output for a set of inputs.

**Efficient frontier:** The set of portfolios that can be found from a given set of investments with the property that each portfolio has the highest possible expected return that can be attained without increasing its volatility.

**Efficient portfolio:** A portfolio that contains only systematic risk. An efficient portfolio cannot be diversified further; there is no way to reduce the volatility of the portfolio without lowering its expected return.

**Energy not supplied:** Electrical Energy (in MWh) not supplied due to outage or supply interruption.

**Externality:** When the production or consumption of some good or services affects the production or consumption of another good or service. Generally arises because the effect is not associated with a price and no market develops to facilitate exchange or regulation.

**Fixed costs:** Costs that cannot vary with changes in production.

**Frequency:** The rate at which alternating current completes a cycle of two reversals of direction. It is measured in Hz, which are cycles per second. The scheduled frequency in North America is 60 Hz, in Europe is 50 Hz.

**Grid:** The transmission network.

**Independent system operator:** An operator of the transmission system that is not owned by any one user of the system.

**Interruptible load:** Load that has a contract stating that it can be interrupted no more than a set of number times per year in return for some compensation, generally a reduction in its rates.

**Load factor:** The ratio of the average load to peak load during a specified time interval.

**Long run:** A time such that no costs are fixed in the production process. Also, the "very long run" implies that technology is not fixed in the production process.

**Marginal cost:** The change in total cost with a unit increase (or decrease) in production.

**Marginal revenue:** The change in total revenue with a unit increases (or decreases) in sales.

**Market clearing price:** The price that all sellers receive and that all buyers pay in a specific time-defined market. Also known as market price.

**Merit order:** A ranking of generators from those with the lowest average variable cost to those with the highest. Also, the ranking by marginal cost of started generators.

**Monopoly:** A condition in which there is a single seller of good or service.

**Natural monopoly:** A situation arising with the technology's positive economies of scale, such that a single firm can produce at the lowest cost.

**Ohm:** The unit of measurement of resistance to the flow of electrical current.

**Oligopoly:** A small group of suppliers that produces the entire output of the product with no close substitutes and as a consequence have market power.

**Operating reserve:** Generation in excess of demand, scheduled to be available on short notice to ensure the reliable operation of a control area.

**Opportunity cost:** The highest alternative value of all resources used in the production of a good or service.

**Peak-load pricing:** A pricing system whereby higher prices are charged during periods of high (electricity) consumption when the marginal cost of production is higher.

**Price discrimination:** The practice of charging different prices to different costumers (with different price elasticities) or charging different prices for different amounts of the good or service.

**Price spike:** A rapid increase and decrease in price.

**Producer surplus:** The difference between the market price and the variable cost of production, summed over all of the output.

**Ramping:** Increasing or decreasing the output of a generator.

**Rate structure:** A set of tariffs charged for each type of service for each customer class.

**Real-time prices:** A pricing system whereby customers are charged the market price at the time of consumption for each unit they consume.

**Security limit:** The power-flow limit imposed on a line to protect it from increased flows caused by unexpected outages of other lines.

**Stability limit:** A line limit based on the stability of the AC power flow.

**Standard deviation:** A common method used to measure the risk of a probability distribution; it is the square root of the variance, the expected squared deviation from the mean.

**Stranded costs:** The difference between a firm's required revenues under regulation and total cost under deregulation.

**Synchronization:** the process of bringing a generator up to speed, making sure its AC voltage is "in step" with the power system voltage, and then connecting it to the system so it can deliver power.

**System operator:** The entity responsible for transmission system operation and reliability.

**Tariff:** The body of regulations governing a power market.

**Thermal limit:** A power flow limit based on the possibility of damage by heat.

**Transmission congestion:** Congestion occurring when a transmission line or interface is not able to transmit more power because it is operating at its maximum transfer capacity.

**Uplift:** A charge imposed on all customers, usually per MWh, that covers costs not covered by prices.

**Variable cost:** Costs that vary with changes in the level of production.

**Variance:** A method to measure the risk of a probability distribution, it is the expected squared deviation from the mean.

**Volt:** The unit of electrical pressure.

**Watt:** The unit of power (electrical energy flow).

**Weighted average cost of capital (WACC):** The average of firm's equity and after-tax cost of capital, weighted by the fraction of the firm's enterprise value that corresponds to equity and debt, respectively.



**VU et PERMIS D'IMPRIMER**



A Montpellier, le

Le Président de l'Université de Montpellier

**Philippe Augé**

## POWER GENERATION ANALYSIS IN OIL PRODUCING COUNTRIES

**Keywords:** *Power Generation, Oil & Gas Resources, Optimal Electricity Generation Means, Economic Rent, Renewable Energies, Nuclear Energy*

**Abstract:** *National power generation mix composition is based on the ranking (merit-order) of the various means of production from their marginal cost of electricity generation. Thus, significant reserves of hydrocarbons in oil-producing countries favoured the abusive use of oil or natural gas in the electricity mix. The purpose of this research is to analyze the power generation mix of these countries by constructing an optimal electricity mix based on the rational use (from an economic point of view) of various electricity production means. In this work, we assess the current and future situation of electricity production in Saudi Arabia, Egypt and Iran, thanks to linear, dynamic and statistical modeling efforts. Thereafter, we will conduct sensitivity analysis to measure the optimality and efficiency of electricity generation by taking into account the integration of alternative non-fossil-fuel based resources.*

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## ANALYSE DE LA PRODUCTION D'ÉLECTRICITÉ DANS LES PAYS PRODUCTEURS DE PÉTROLE

**Mots-clés:** *Production d'Électricité, Ressources d'Hydrocarbure, Parc optimal d'électricité, Rente Économique, Énergies Renouvelables, Énergie Nucléaire*

**Résumé :** *La composition des parcs électriques nationaux est basée sur le classement des différents moyens de production par rapport à leur coût marginal de génération d'électricité. Ainsi, les réserves considérables d'hydrocarbure dans les pays producteurs de pétrole ont favorisé l'usage abusif du pétrole ou du gaz naturel dans le parc de production d'électricité. L'objectif de ce travail de recherche est d'analyser des parcs de production pour ces pays producteurs en construisant le parc optimal d'électricité concernant l'usage rationnel (du point de vue économique) des différents moyens de génération d'électricité. Dans ce travail, nous évaluons la situation actuelle et future de la production d'électricité en Arabie Saoudite, en Égypte et en Iran grâce à plusieurs approches de modélisation : linéaire, dynamique et statistique. Ensuite, nous allons mener une analyse de sensibilité afin d'évaluer l'optimalité et l'efficacité de la production d'électricité en tenant compte de l'intégration des autres ressources alternatives non-carbonées.*